Economic Potential for Alternative Transportation Fuels: Methanol, Ethanol, Propane, Liquefied Coal, Compressed Natural Gas and Hydrogen

Proceedings of a Seminar Held on November 17, 1981, Calgary, Alberta

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1. Introduction

The rising price of oil and oil-derived products, coupled with an uncertain political and economic climate, has spurred interest in alternative liquid fuels, particularly for use in the transportation sector. Potentially, several fuels could successfully displace gasoline as a fuel in a certain percentage of vehicles. The economics of supply and demand, as well as the technology required to produce these fuels has, in many cases, not been well documented.

The seminar held on November 17, 1981, was organized to obtain feedback from industry representatives on tentative conclusions made by Charles Slagorsky in a study then in progress on the relative economic potential of six transport fuels. The seminar was organized to permit considerable general discussion in addition to presentations prepared by seminar participants. The speakers and general participants had considerable expertise in the area of transport fuel economics. Their presentations and comments have been brought together in this publication in order to make them available to a larger audience.

2. Economic Potential for Alternative Transportation Fuels

Z. Charles Slagorsky
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A subjective choice of six fuels: methanol, ethanol, propane, compressed natural gas, liquefied coal and hydrogen was made to consider what are believed to be the most viable choices in the remaining part of the 20th century, but mostly in this decade.

Why do I say 'alternative fuels'? an 'alternative' to what?

The reduction of the dependence of the Canadian economy on crude oil is a major policy objective on the way to oil self-sufficiency by 1990, or, as some would say, by the mid-1990's. The transportation sector alone uses some 30 percent of total energy consumed in a typical year and so a reduction of the use of crude oil-derived fuels in this sector will help reach the objective of self-sufficiency.

The reduced dependence on fuels derived from crude oil in transportation calls for a careful look at what other suitable fuels there are. Although this is what we are trying to do, there are a number of difficulties which many people in this room are aware of or may begin appreciating at the end of this meeting.

Some of the general observations applicable to the economic analysis of alternative fuels include the following:

(1) The quality and reliability of economic analysis of this type is to a large degree determined by the quality and reliability of the cost data. This is particularly so in those cases where no commercial production exists at present. Generally, the most reliable estimates are those based on engineering-economic analysis. But the lack of availability of 'hard data' is a serious problem.

(2) A common error is often made when comparing cost estimates of alternative fuels with the cost of crude oil. While the cost of crude oil is often assumed to be rising in the future, there is a tendency to assume that the estimated cost of the alternative fuels will be held constant. Therefore a bias often results.

(3) Useful analysis must attempt to compare the various fuels on the same or equal basis. All subsidies should be removed so that the alternatives are compared on an equal footing. For the purpose of comparison, the fuels must stand on their own.

(4) The final observation relates to the strategies available to achieve a reduction in the use of gasoline in transportation. There clearly are two ways of using less gasoline: one is to improve vehicle fuel efficiency (which will cost money for new designs); and the other is to switch to alternative fuels (which will also cost money--on conversions, new facilities and distribution networks). These two ways of using less gasoline could alternatively be viewed as two investment opportunities. If the two strategies are integrated, the extent to which improved fuel efficiency is cost-effective relative to using an alternative fuel can be demonstrated. There will be different distribution effects of these two approaches.

The main objective then is to compare the costs of using gasoline in transportation to the cost of using the six alternative fuels selected here.

Methanol

A number of options exist in the production of methanol, both in the sources of feedstock and the conversion technology.

Because the production of most alternative fuels (and synthetic fuels generally) is capital intensive, the cost of the final product is extremely sensitive to assumed rates of return, the ratio of debt to equity capital employed and to the rate of interest paid on borrowed capital. Very different results can be obtained with changes in these parameters.

Depending on the cost of feedstock and the location of the plant, the estimates of the cost of methyl fuel would be comparable to between $25 and $65 per barrel of crude oil. This does not mean, however, that methanol as a fuel then becomes price-competitive with transportation fuels derived from crude oil. Not included are considerations for:

(1) motor vehicles' (and other end-uses) new designs

or

conversions,

(2) methanol distribution system, and

(3) an explicit account of the lower Btu content of methanol vs. gasoline.

Examples of one possible method of arriving at an estimate of the cost of producing methanol are shown on the following table (Table 2.1).

To arrive at an estimate of the cost of methanol comparable with the current price of gasoline, one can conveniently begin with the present market price of commercially produced chemical methanol. The figures in the table are, of course, based on current conditions and they agree with several other available studies looking at methanol's future cost. Any future relative changes in the price of gasoline or methanol will, of course, change the picture. Recent energy agreements suggest that the future price of gasoline, for example, will rise more rapidly than general inflation. If the production cost of methanol rises only with inflation, methanol will begin looking more attractive relative to gasoline, particularly in eastern Canada. The actual inflation of the cost of new methanol facilities will, of course, be very important in determining future relative prices of methanol and gasoline.

Ethanol

The biggest problem in ethanol production is the high cost of feedstocks. This is because biomass resources suitable for ethanol production (grains, sugar beets, etc.) do not have high energy density, are dispersed in their occurrence, and may command considerable value in non-energy uses such as food production or livestock feed (i.e., the

TABLE 2.1

THE COST OF METHANOL[a] VERSUS REGULAR GASOLINE

	Cents per Litre
Methanol Cost:	
Current selling price	24.0
Penalty for lower Btu content relative to gasoline	15.6
Allowance for engine modifications	1.2
Distribution cost	3.5
Total estimated cost	44.3
Gasoline Cost:	
Calgary	30.0
Toronto	39.0

[a]Based on the market price of methanol and gasoline in the summer of 1981.

so-called 'food-fuel conflict'). As a supplement to automotive fuel in the form of gasohol (10 percent ethanol and 90 percent gasoline) ethanol could help to lessen the Canadian dependence on foreign supplies of crude oil, especially if produced from spoiled or surplus crops grown on marginal land, or, as in the case of Mohawk Oil, if produced in idle distilleries.

Depending on the type and cost of feedstock, and other assumptions, available estimates of ethanol's production cost range from a low of about 39 cents per litre to a high of 95 cents per litre. One available estimate shown on the next diagram (Figure 2.1) specifies the relationship between the cost of two kinds of feedstock and the cost of ethanol; while the following figure (Figure 2.2) shows the estimated rates of return on ethanol production.

Propane

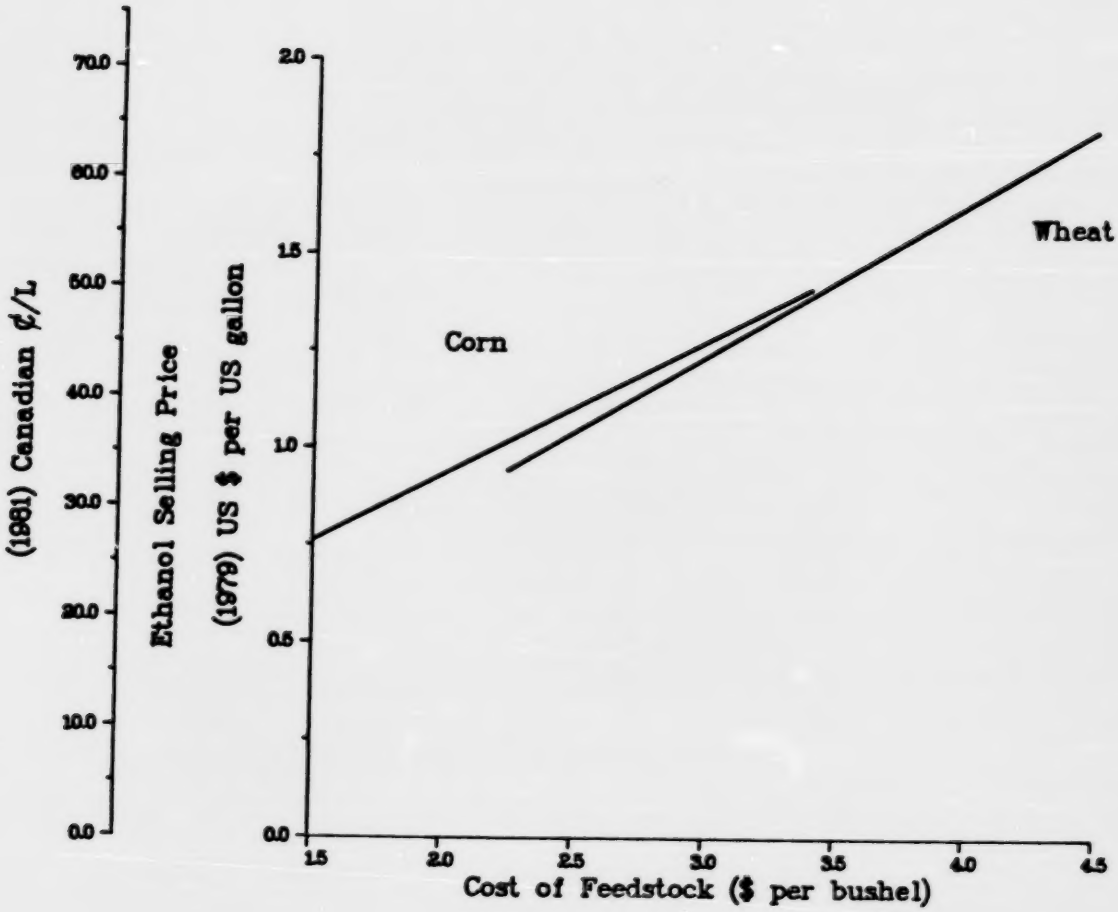
With the rising price of gasoline, the competitiveness of propane as a transportation fuel has recently been improving; and the NEP has made it an objective to increase the use of propane.

Again, the relative prices of these two fuels will be all-important.

Since the mileage is about equal for propane as for gasoline, it can be assumed that the only extra cost associated with the use of propane is the cost of engine conversion. A market survey in Calgary resulted in the following cost estimates for engine propane conversions (Table 2.2).

Given this information and some additional assumptions, the current market price of propane can be compared to that of gasoline to arrive at an estimated pay-off period required for the cost of propane conversion (Table 2.3 and Figure 2.3).

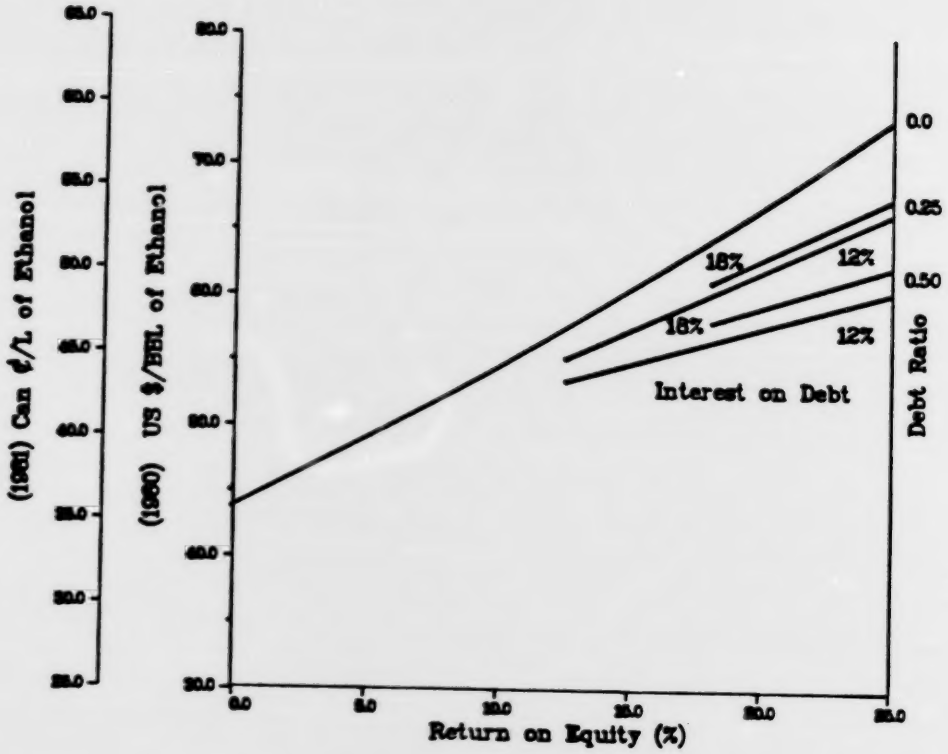
The annual savings depend heavily not only on the miles travelled and the vehicle mileage, but also on the difference between the price of propane and gasoline. That difference has in fact been growing in recent months. Between March and September of 1981, the price of gasoline increased in Calgary by 39 percent, whereas the price of propane rose only by 6.7 percent. The spread between the two prices thus



Assumes: –100% equity financing
–15% DCF
–20 yrs. operating life
–US location

Source: US Dept. of Energy, The Report of the Alcohol Fuels, op. cit., p. 93.

FIGURE 2.1: SENSITIVITY OF ETHANOL SELLING PRICE TO FEEDSTOCK COST



Assumes: -Ethanol production from corn
-3,068 BBLS/D plant capacity
-US location

Source: Bechtel Corp., quoted in R.H. Shackson, op. cit., p. 90.

FIGURE 2.2: ESTIMATED RATE OF RETURN ON ETHANOL PRODUCTION

TABLE 2.2

ESTIMATED COSTS OF VEHICLE PROPANE CONVERSION (CALGARY)

Type of Vehicle	Cost per Vehicle in $ (parts and labour)
Small car (e.g.· Honda Civic)	900 - 1,000
Taxi (full-size North American car)	1,500 - 1,700
Light truck	1,400
Heavy truck (3 - 5 ton)	1,800
Van	1,300 - 1,400

SOURCE: CERI market survey of three propane conversion shops in Calgary, Summer, 1981.

TABLE 2.3

THE VIABILITY OF PROPANE VEHICLE CONVERSION

(i) Assumptions:

- Vehicle A travels 10,000 miles per year
- Vehicle B travels 20,000 miles per year
- Mileage is equal between gasoline and propane
- Both vehicles travel 20 miles per gallon of gasoline
- Annual cost for oil changes and propane engine maintenance is one half of that of a gasoline-powered engine (assumed to be $100)

(ii) Current Fuel Costs (Calgary, September, 1981)

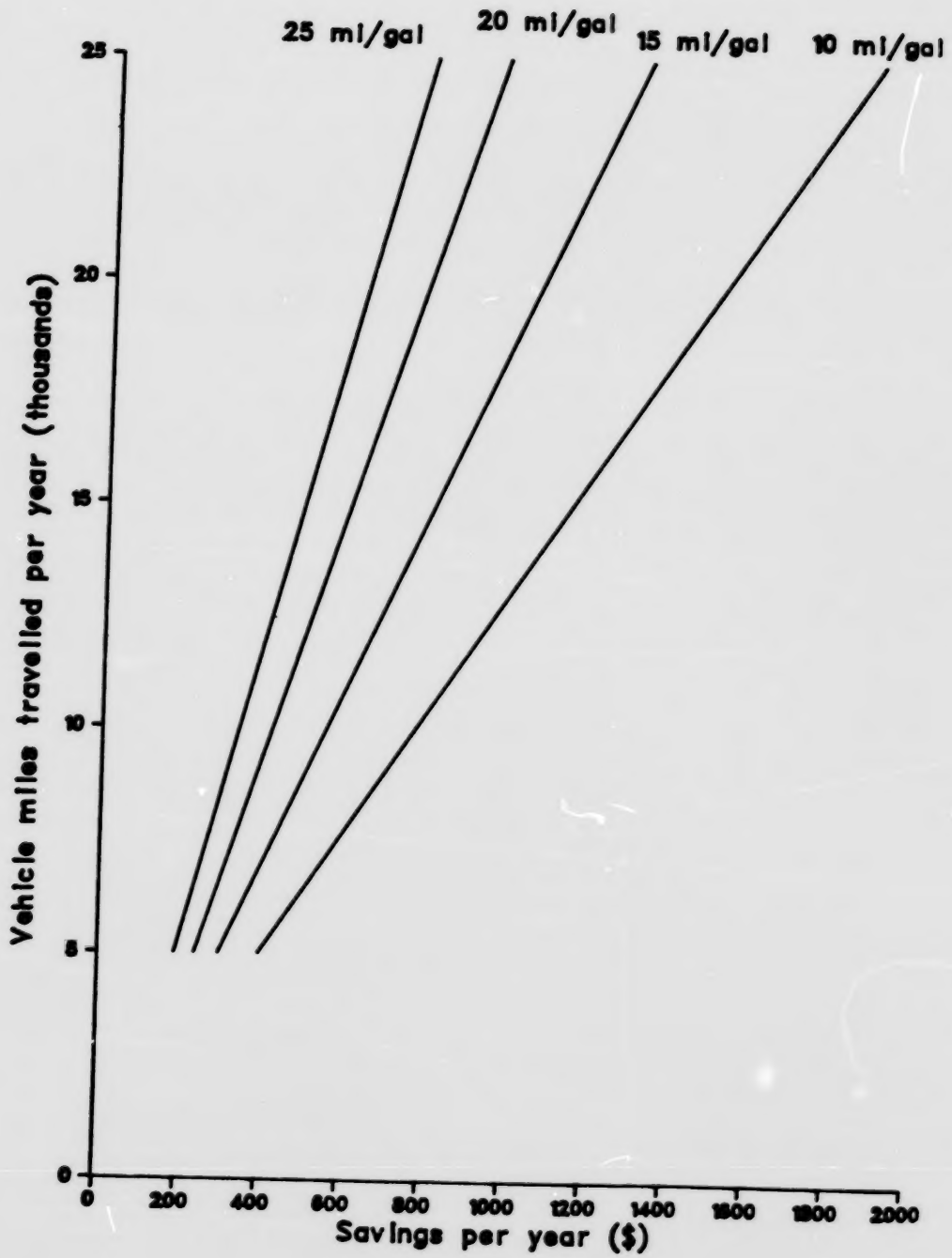
- regular gasoline 32¢/L
- propane 16¢/L
- propane advantage 16¢/L or $.727/gallon

(iii) Annual Savings Due to Conversion

- Vehicle A:
  (10,000 ÷ 20) x .727 = $363.50/year
- Vehicle B:
  (20,000 ÷ 20) x .727 = $727.00/year
- Maintenance saving $50.00/year

(iv) Total Savings

- Vehicle A: $413.50/year
- Vehicle B: $777.00/year



SOURCE: Based on Table 2.3

FIGURE 2.3: VARIATIONS OF SAVINGS ON PROPANE CONVERSION

increased by 78 percent (from 9¢/L to 16¢/L). These developments make propane conversions more attractive.

The two important questions in the minds of those who contemplate a conversion to propane are:

(1) At what rate will the cost of conversion rise in the future, or will it perhaps even fall or stay constant if conversion kits become available on a wide scale?, and

(2) What will happen to the difference between the price of gasoline and propane?

As to the first question, one can assume the cost rising with inflation. As to the second question, the answer is more difficult.

If the price of propane tracks the price of natural gas, then propane will be attractive as an alternative vehicle fuel. If, however, the price of propane tracks the faster rising price of crude oil, the price spread between propane and gasoline may stay constant or even diminish, rendering propane conversions less attractive.

Compressed Natural Gas (CNG)

The economics of CNG are not dissimilar to the case of propane, although the conversion cost is higher. The next table (Table 2.4) shows an example of the calculations of savings possible for a CNG conversion which are then plotted on the next diagram (Figure 2.4).

The two important questions again are: (1) at what price will CNG distributors be able to buy natural gas; and (2) what will happen to the future cost of conversion? Here it is assumed that the natural gas is obtained at $2.60/Mcf, although natural gas as a petrochemical feedstock is sold in Alberta for around $1.90/Mcf and in B.C. for around $1.67/Mcf. For comparison, the export price is $5.80/Mcf. Thus, a price slightly above $2.00/Mcf seems realistic.

Although the discussion of the economics of propane and CNG conversions presumes a competition between the two fuels, it is more appropriate to see them as two viable near-term (i.e., this decade) alternative ways of moving off oil in the transportation sector. The two fuels can exist side

TABLE 2.4

THE VIABILITY OF CNG CONVERSION

(i) Assumptions:

- Vehicle A travels 10,000 miles per year
- Vehicle B travels 25,000 miles per year
- Both vehicles travel 20 miles per gallon of gasoline
- Combustion energy content of 1 gallon of gasoline = 143,055 Btu, 1 cubic foot of natural gas = 950 Btu and thus 1 gallon of gasoline = 150.58 cu. ft. of natural gas
- Cost of gasoline - $1.45/gallon (32¢/L)
- Maintenance cost savings when using CNG is $50/year
- Cost of natural gas = $2.60/Mcf
- The basis for comparison is the combustion energy content

(ii) Current Gasoline Cost (Calgary, September, 1981):

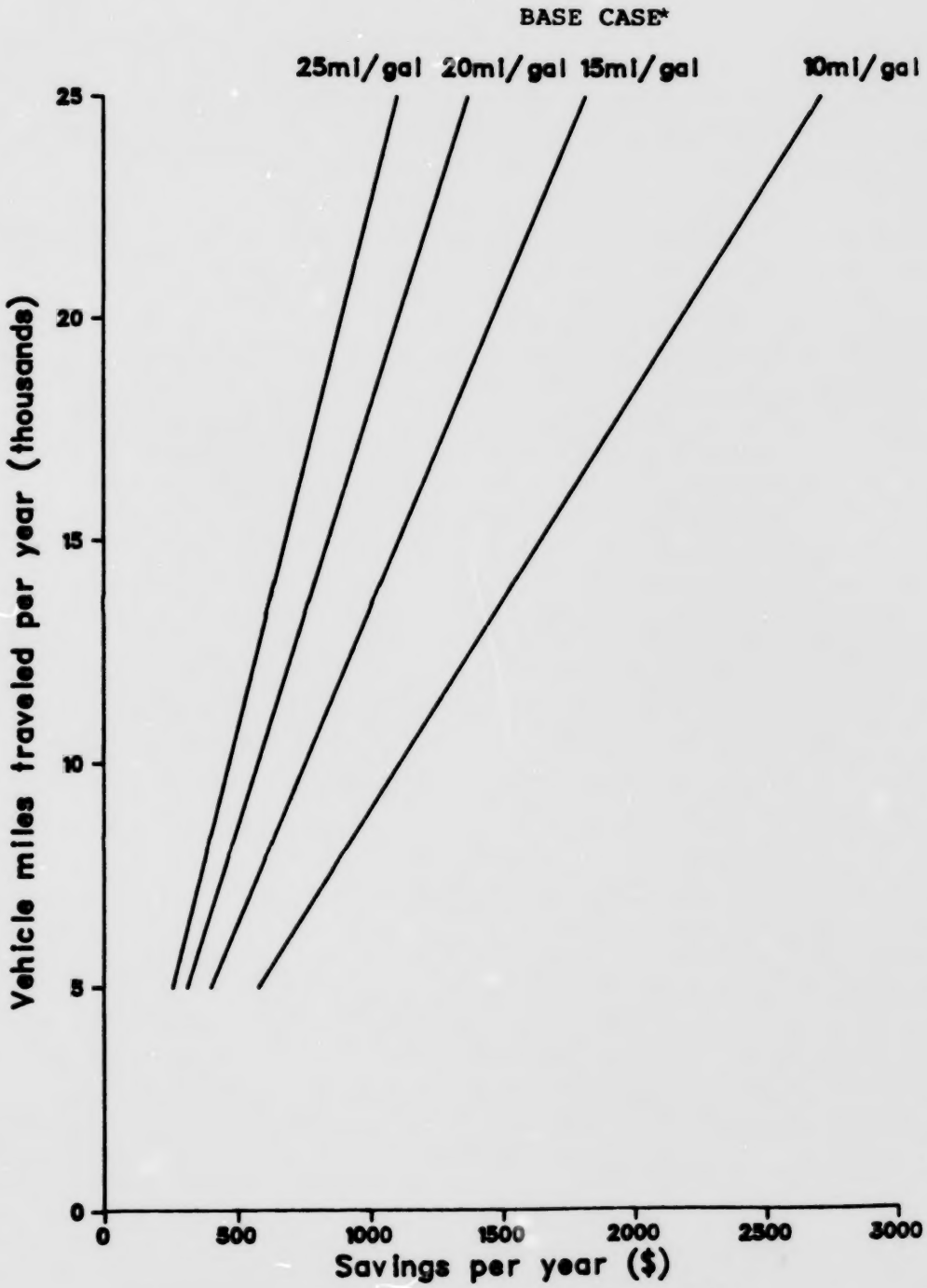
- Vehicle A:
  (10,000 ÷ 20) x 1.46 = $730.00/year
- Vehicle B:
  (25,000 ÷ 20) x 1.46 = $1,825.00/year

(iii) Equivalent Cost of CNG:

- Vehicle A:
  500 x 150.58 = 75,290 cu. ft.
  = 75.29 Mcf x 2.60 = $195.75/year
- Vehicle B:
  1,250 x 150.58 = 188,225 cu. ft.
  = 188.225 Mcf x 2.60 = $489.39/year

(iv) Total Savings:

- Vehicle A: 730.00 - 195.75 + 50.00 = $584.25/year
- Vehicle B: 1,825.00 - 489.39 + 50.00 = $1,385.61/year



*Assumes natural gas at $2.60 per Mcf

SOURCE: Based on Table 2.4

FIGURE 2.4: VARIATIONS OF SAVINGS ON CNG CONVERSION

by side, much like diesel and gasoline exist now. Out of the several alternatives discussed today, propane and CNG are also the closest to having a distribution system in place.

Liquefied Coal

Although coal liquefaction technology is well known and a commercial production currently exists in South Africa, an economic assessment of the production of liquids from coal tends to favor other fuels. Particularly the oil sands--the 'natural' alternative to coal in the production of liquid fuels--appears more economical. This is primarily because the chemical properties of oil sands (bitumen) are closer to the final refined products than those of coal. It also seems cheaper to extract oil sands (surface mining) than coal on an equal scale.

Recent technical and economic sources contain a number of cost estimates some of which suggest that liquid fuels from coal may be nearly competitive with oil sands. The only way to verify the estimates, however, would be to build a commercial-scale plant. Available Canadian estimates range between $25 and $44 per barrel of coal liquids, but these estimates usually do not include taxes and royalties, or, rather importantly, the cost of developing or opening a suitable coal mine. It is worth mentioning that a coal liquefaction plant would require a coal feed capacity far beyond that of a typical Canadian mine.

There are a number of other estimates originating in the U.S. where more research and feasibility studies regarding coal liquefaction have been undertaken. Many of these figures are appreciably higher than the above $25 to $44 per barrel range. For example, a study by Oak Ridge National Laboratory estimated the cost of coal liquefaction to be between $37 and $52 per barrel; Exxon Research and Development estimated in 1980 that a full-scale commercial plant would have to sell coal liquids for about $61 per barrel to be economical and one very recent estimate put the price around $70 per barrel. (Dr. Eric Willis, 6th Canadian National Energy Forum, Nov. 9-10, 1981.)

A large-scale production of liquid fuels from coal would also necessitate modifications to existing refineries, adding further to the cost of the final product.

It is clear that coal liquids will be expensive but precisely how expensive we will not be able to tell before an actual commercial operation begins. The task now is perhaps to bring the technology to a stage of commercial readiness so that a full-scale plant can be designed with an acceptable level of risk. In this aspect coal liquefaction is not unlike the oil sands production in its beginnings in the 1960's and the 1970's. Although the production technology was known, the Suncor plant (then G.C.O.S.) did not turn profit for a long time after its commencement in 1967. Also, various technological problems plagued the Syncrude plant following its inception in 1978, with the plant still not operating at the designed full capacity in 1981.

Early optimistic cost estimates of the production of oil from the oil sands, too, kept being revised upwards to the levels of the world market price for oil prevailing at present. Thus, although coal liquefaction appears to be a technologically mature alternative, other fuels could seemingly be produced at a lower cost. Further development will depend on technological improvements and the changes in the world price of oil.

Since Canada has truly vast coal reserves, coal liquefaction presents a secure long-term alternative source of transportation fuels, where the higher production cost could be thought of as the premium paid for the secure indigenous supply.

Hydrogen

One thing which can be said about hydrogen with certainty is that it is now being taken seriously as an alternative fuel, albeit with a somewhat more distant horizon. It is no longer foreseen, as it was in 1976, that there would be 15 oil sands plants operating in Canada by the turn of the century. The mood now is characterized by a long-term search for alternatives to crude-oil-derived fuels, many of which are renewable. While methanol could be considered as a medium-term alternative, hydrogen is an alternative for the long-term, most likely beyond the year 2000.

An economic assessment of hydrogen as a fuel is difficult; more difficult in fact than that of the other fuels we have discussed. We are faced with a much greater

technological uncertainty in the case of hydrogen than, say, in propane or methanol. The amount of general technical knowledge and expertise assembled to date is smaller in the case of hydrogen relative to other alternatives.

Actual cost estimates for hydrogen are very scarce and unreliable. If hydrogen were to be produced from water via electrolysis, then the main component of production cost would be the cost of electricity. It is often asserted that cheap electricity will be available, especially in the large consuming provinces of Quebec and Ontario. It is true that Canada should not have a shortage of electricity or resources from which electricity can be produced. Theoretically, hydrogen may in fact offer considerable advantages over electricity in terms of storage and transportation.

U.S.-based Billings Energy Corporation (acting as a consultant to the U.S. Department of Energy) estimated in 1980 that the cost of gaseous hydrogen for use in internal combustion engines would be the equivalent of 95 cents (U.S.) a gallon. Liquid hydrogen, on the other hand, would be about four times as expensive as jet fuel. The Canadian Hydrogen Energy Society has put the estimate of hydrogen cost at (1980) $1.25 per gallon of gasoline equivalent if cheaper off-peak electricity were utilized.

A recently completed hydrogen task force study in Ontario concluded that if Ontario Hydro is permitted to build 'hydrogen-committed nuclear capacity', the electricity cost could be reduced by 21 percent in constant dollars by the year 2000. Correspondingly, in 1980 dollars, the cost of electrolytic hydrogen could be reduced from $8.20 per gigajoule in 1980 to $6.10 per gigajoule in 2000. In the same time period, hydrogen produced from natural gas would increase from $5.20 per gigajoule to about $15.50 per gigajoule.

Converting natural gas into hydrogen for the purpose of obtaining a transportation fuel does not seem to be a very sound engineering or economic practice since the former can be used in transportation more readily and efficiently in the form of methanol, propane or CNG.

On the basis of currently available cost information, therefore, it seems that only hydrogen produced from water via electrolysis would be a viable method of obtaining an alternative transportation fuel, given that plentiful

cheap electricity is available and that distribution problems as well as those of end-use conversion can be overcome.

Concluding Comment

The cost estimates for the alternative liquid fuels presented here are, of course, only tentative. The development of these fuels will only materialize within an institutional framework wherein investors find it possible and attractive to invest in the production of the fuels and consumers are encouraged to switch to them. It is worth noting that it is in the market place that the development and marketing problems associated with the alternative fuels would be solved in an efficient manner. Once the market signals are 'right' owners of resources, fuel refiners, and vehicle and home furnace manufacturers may be expected to undertake the necessary research and development required to minimize the technical risk of production. Once new products designed to run on alternative fuels are developed at competitive prices, consumers, too, may be expected to make the switch.

The next figure (Figure 2.5) summarizes the current cost estimates of the fuels considered here and compares them with the cost of conventional crude oil and oil from the oil sands. In the case of each of the alternative fuels, a 'base-case type' unit cost has been selected for this comparison. When making a comparison between the fuels listed, it should be kept in mind that even for the base-case, very different numbers can be obtained depending on the various assumptions which must be made for more detailed calculations. The estimates contained in Figure 2.5 are thus no more than 'ball-park figures' which should serve the purpose of comparing orders of magnitude only.

It can be seen that, in Canada, we have two short-term alternative fuels--propane and compressed natural gas--available in sufficient quantities and at a lower cost than the current comparable cost of gasoline. Indications are that in larger Canadian cities such as Toronto, Vancouver, Winnipeg, Calgary, and elsewhere, some motorists have already begun switching away from gasoline albeit thus far only in small numbers.

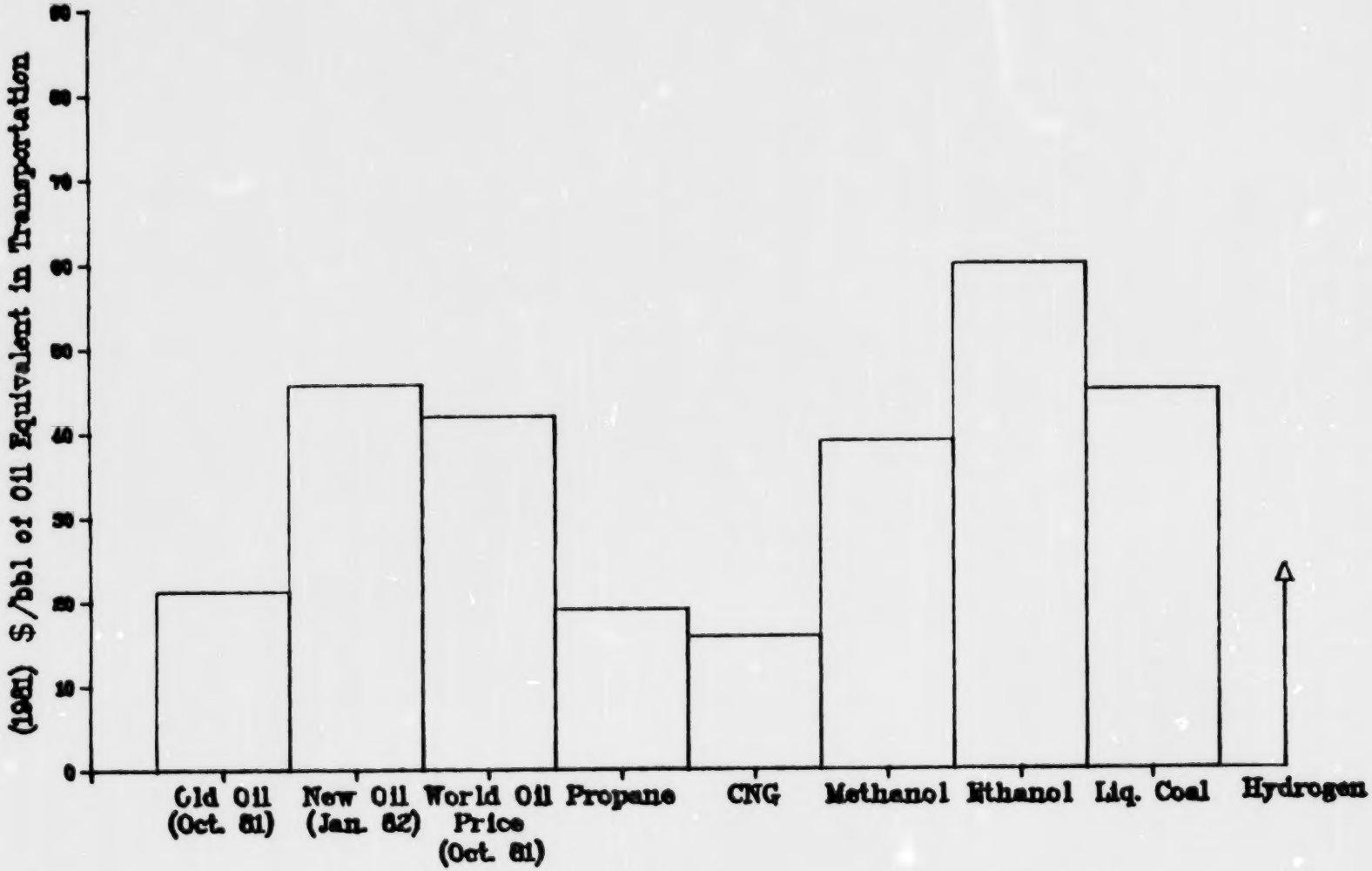


FIGURE 2.5: COMPARATIVE COST OF ALTERNATIVE FUELS

In addition there are two available medium-term liquid fuel options--methanol and liquefied coal--which may be used during the interim period within which Canada switches its energy base (away from the hydrocarbons) if and when such a switch is deemed timely and appropriate. Ethanol's production seems too expensive and the cost of using and producing hydrogen on a large scale is at present too uncertain to be assigned a specific number.

As suggested at the beginning of the chapter, it would be interesting to compare these (marginal) cost estimates of producing alternative transportation fuels to the estimates of marginal cost of gasoline savings due to improved vehicle fuel efficiency since, clearly, there are two alternative ways of reducing our current consumption of gasoline. Improved fuel economy can be expressed in dollars per litre of reduced fuel consumption. This can be done in the following way.

The 1979 model year was selected as the starting year for comparison because it was the most recent year for which complete production and technological data were available. The reduced fuel consumption for cars was calculated on an annual incremental basis, showing the relative reduction in fuel use from one model year compared with the previous model year. As a result, the marginal consumer cost of fuel savings was derived and is shown for the period from 1980 to 2000 in the next figure (Figure 2.6). The marginal cost of any fuel-saving technological improvement will be much less now when that technology can reduce fuel consumption by proportionately greater amounts. As initial savings of fuel are realized, the relative reductions decline significantly, adding more and more to cost. When an average of 38 to 42 miles per gallon or more is reached (which is assumed to be the case by the year 2000), further percentage increases in fuel economy produce very small savings.

An interesting comparison can be made between the costs of the two alternatives. For reasons of policy, this is a rather important piece of information. It can be seen that on the basis of cost, improved vehicle fuel efficiency, particularly during the early part of this decade, appears to be the preferred alternative. But as initial fuel savings are realized, further improvements tend to be more and more

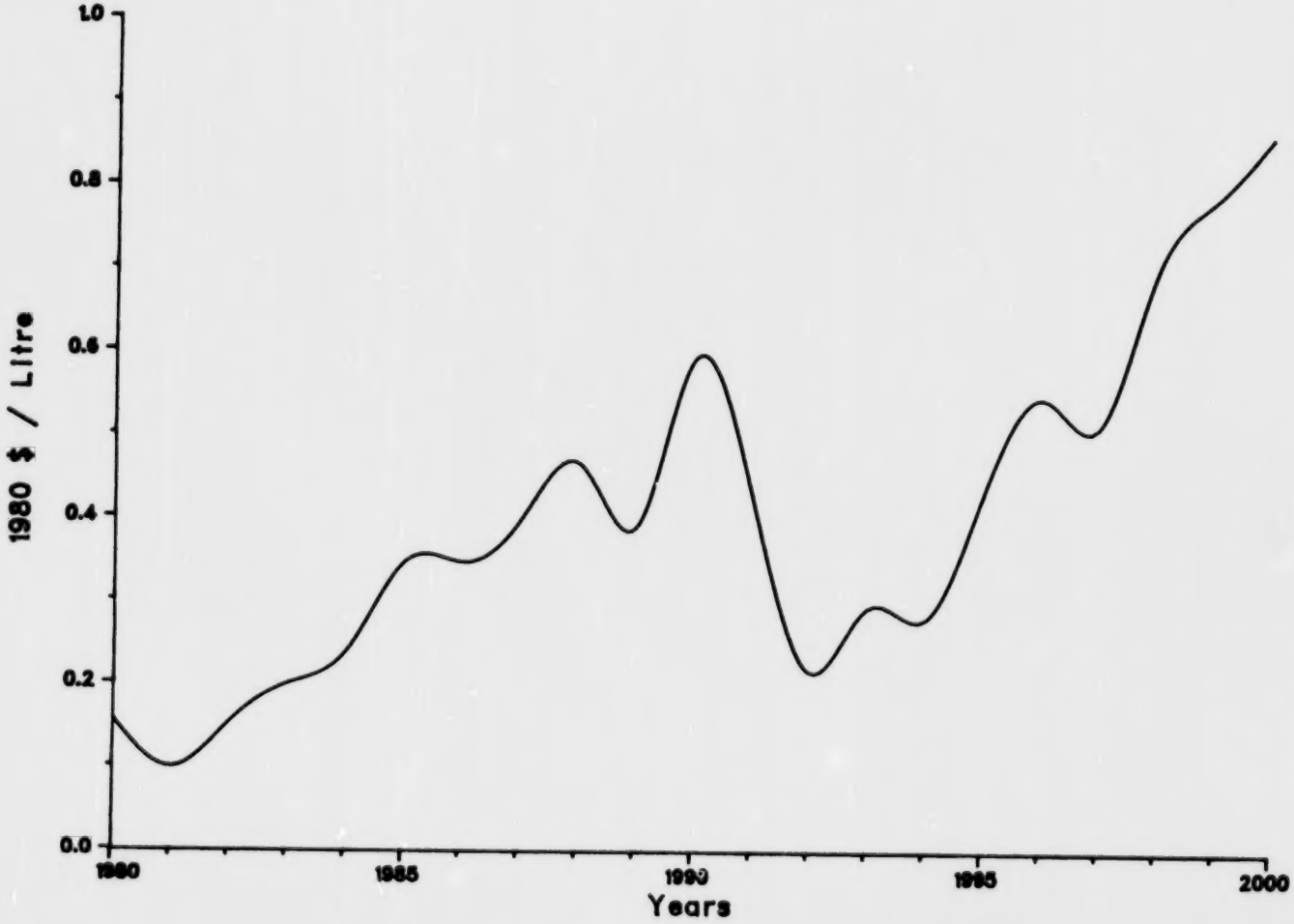


FIGURE 2.6: MARGINAL COST OF FUEL SAVED

SOURCE: R. H. Shackson and H. J. Leach, Maintaining Automotive Mobility, Arlington, Virginia: Mellon Institute, 1980, p. 63.

costly. In other words, the marginal cost curve for a more fuel efficient design eventually rises steeply. Assuming no changes in constant dollar relative prices between the two types of cost, the cost levels of the alternative fuels discussed in this chapter could be projected across the diagram in Figure 2.6 to see which fuels and when will be cost-preferred to greater fuel conservation.

Our last, but most definitely not least, caveat for those interested in the relative prices of alternative fuels is in order. Currently, the system of collecting revenues by various levels of government is done rather effectively through taxes imposed on transportation (and heating) fuels collected at the pump. If the consumption of gasoline were to be reduced due to a large-scale switching by vehicle owners to other fuels, governments cannot be expected to wait too long before imposing additional taxes on alternative fuels to keep their revenues from falling.

Relative fuel prices would thus again be changed with previous incentives diminishing or disappearing. The case of gasoline and diesel can serve as an example. This real possibility of a relative price increase for a given alternative fuel once motorists have converted to its use is perhaps the strongest uncertainty presently facing potential propane and compressed natural gas users. Without this obstacle, many more motorists would find these fuels more attractive than gasoline today.

Other general problems may include:

(1) Fleet car operators do not pay retail price for gasoline which would affect the analysis of savings with propane and CNG conversions.

(2) Technical problems such as with propane's tendency to settle down and evaporate (problems for tunnels...).

(3) Making methanol or ethanol on farms (small-scale) from agricultural resources may prompt much higher insurance premiums due to the various dangers involved, etc.

3. Economic Potential of Methanol as an Alternative Fuel

M. D. McDonald
Economist
Energy Resources Conservation Board

I will begin this presentation by summarizing a paper entitled "A Comparison of Coal & Gas as Feedstocks" for NH_4 and CH_3OH production in Alberta which I gave in Halifax in June 1981.

Methanol Synthesis

Methanol can be derived from a variety of sources including oil, natural gas, coal, and some biomass materials.

The following reactions illustrate how methanol can be produced:

(1) The reaction of hydrogen with carbon monoxide or carbon dioxide at 200°C-300°C and at 100-200 KPa over a copper based catalyst.

$$2H_2 + Co \longrightarrow CH_3OH$$
$$3H_2 + Co_2 \longrightarrow CH_3OH + H_2O$$

(2) Steam methane reforming.

$$CH_4 + H_2O \longrightarrow CO + 3H_2$$

There are two main reasons why alternative feedstocks for the production of methanol are being considered:

(1) From a resource conservation point of view, natural gas would be used as a substitute for the depleting domestic crude oil or the more expensive foreign crude oil.
(2) From an economic point of view, since the projected price or social value of natural gas may be higher than some other resources on a unit joule basis, it might be viable to produce methanol from an alternative feedstock.

Coal, one of the most plentiful fossil energy resources in Alberta, is a prime candidate to substitute for natural gas

as a feedstock in the manufacture of methanol. The reasons for using coal are:

(1) There is a large reserve of low sulfur sub-bituminous coal in Alberta.

(2) Commercially proven technology is available to obtain hydrogen, carbon monoxide and carbon dioxide by gasifying coal.

(3) More importantly, the present and projected coal prices are much lower than that of natural gas on a unit joule basis.

Technical Evaluation:

Process Model

Capital and operating cost for both coal-based and gas-based plants were extracted from literature. A model was developed to standardize the capital costs. Figure 3.1 illustrates the structure of this process model.

The following is a list of the conditions under which this model was developed:

- grass-roots coal-based plant at Alberta mine mouth.
- grass-roots gas-based plant in Central Alberta
- first generation gasification process
- methanol production rate - 2000 tonnes per stream day
- 330 stream days per year
- 1980 constant dollars
- 1.20 cost contingency factor for coal-based plant
- 1.10 cost contingency factor for gas-based plant
- Alberta sub-bituminous coal
- coal preparation plant product specification: moisture 8 percent and ash 8 percent

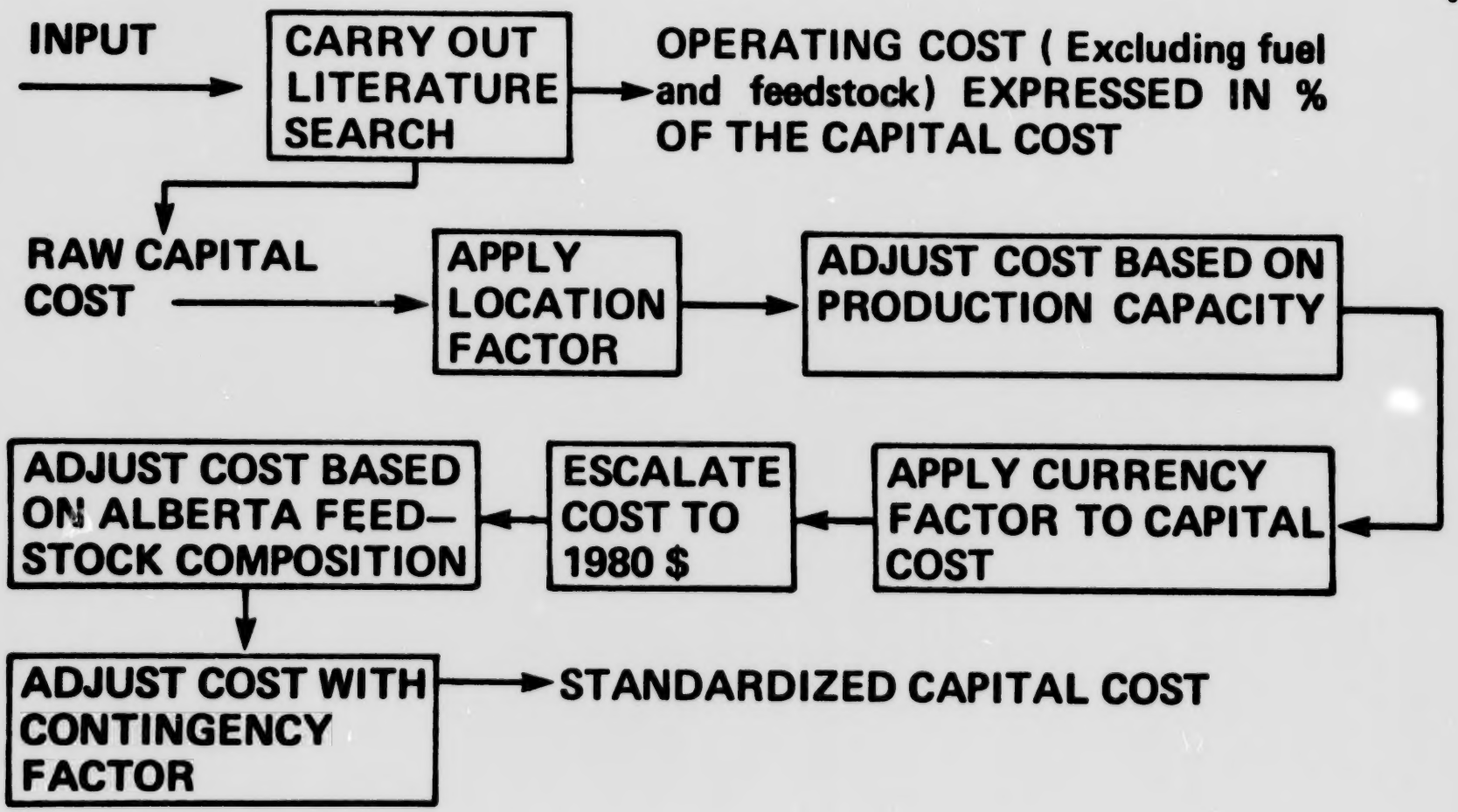

INPUT
CARRY OUT LITERATURE SEARCH
OPERATING COST (Excluding fuel and feedstock) EXPRESSED IN % OF THE CAPITAL COST
RAW CAPITAL COST
APPLY LOCATION FACTOR
ADJUST COST BASED ON PRODUCTION CAPACITY
APPLY CURRENCY FACTOR TO CAPITAL COST
ESCALATE COST TO 1980 $
ADJUST COST BASED ON ALBERTA FEED-STOCK COMPOSITION
ADJUST COST WITH CONTINGENCY FACTOR
STANDARDIZED CAPITAL COST

FIGURE 3.1: STANDARDIZED CAPITAL COST METHODOLOGY

Several specific economic assumptions were made. These are listed in Table 3.1.

From this analysis high, low and base cases were developed. A range of capital and operating costs were obtained and these are shown in Table 3.2.

The present value of the unit cost of methanol produced from coal, as well as gas, were calculated from the costs shown in Table 3.2. These results are shown in Table 3.3 and are also illustrated in Figure 3.2.

The sensitivity of the calculations to the capital cost variations of the coal conversion process detract from the conclusiveness of the results. The results do, however, illustrate the commercial advantage of coal conversion to methanol, if it is discovered that the true capital and operating costs are consistent with the low coal-cost case. They also demonstrate the potential for the commercial advantage of coal conversion before 2000, if the costs are consistent with the base case.

Given the nature of the results, consideration should be given to determining the true social value of gas (or the price which society would pay in the absence of regulated prices), to ensure the two resources become competitive (possibly through the introduction of government incentives or removal of price regulations) at the optimum point in time. Pricing gas at the export price appears to eliminate the currently perceived competitive advantage of gas over coal (as exemplified by Case F). Since the export price may be considered the opportunity value of the gas, the results strongly suggest the economic advantage to society of beginning the shift to coal as the methanol feedstock during this decade.

Several observations can be made:

- currently the cost of methanol levelized over a plant life ranges from 16-24 cents per litre
- larger plants (i.e., 30-50 mtpd) would lower this unit cost
- coal conversion to methanol may become competitive in the late 1990's
  (Note: if coal conversion in Alberta becomes competitive it is likely that coal conversion in the U.S. will become competitive first, thus shifting the center of production)

TABLE 3.1

ECONOMIC CRITERION

- TAX RATE = 41% = 30% FEDERAL + 11% PROVINCIAL
- CCA = 50% ST. LINE FOR COAL; CCA = 30% DECLINING BALANCE FOR GAS
- FLOW – THROUGH TAXATION
- INVESTMENT TAX CREDIT = 7%
- 20 – YEAR LIFE
- REAL RETURN TO EQUITY = 15% (AFTER TAX)
- REAL RETURN TO DEBT = 5%
- D/E = 50/50
- WORKING CAPITAL = 5%
- DISCOUNT FACTOR = 10%
- INFLATION RATE = 10%

TABLE 3.2

RANGE OF COSTS UTILIZED FOR METHANOL PLANTS

CAPITAL COSTS (IN 1980 DOLLARS) WERE AS FOLLOWS.

CAPITAL COST $M	CASE
300	LOW COST COAL PROCESS
525	MEDIUM COST COAL PROCESS
750	HIGH COST COAL PROCESS
226	GAS PROCESS

OPERATING COSTS (NET OF FUEL AND FEED) WERE AS FOLLOWS.

PER CENT OF FIXED CAPITAL COST	CASE
6	LOW COST COAL PROCESS
9	MEDIUM COST COAL PROCESS
12	HIGH COST COAL PROCESS
7	GAS PROCESS

TABLE 3.3

METHANOL

Case	First Year of Construction $/tonne of Methanol	
	1980	2001
A - coal high capital and operating cost	383	383
B - coal base case (medium costs plus coal at $12/t)	248	248
C - coal low capital and operating cost	146	146
D - coal medium cost (coal price increase)	256	272
E - coal medium cost (coal price low)	236	236
F - gas (gas at export price and increasing)	310	387
G - gas (gas at 70% of ABP and increasing)	151	203
H - gas (gas at ABP and increasing)	202	257

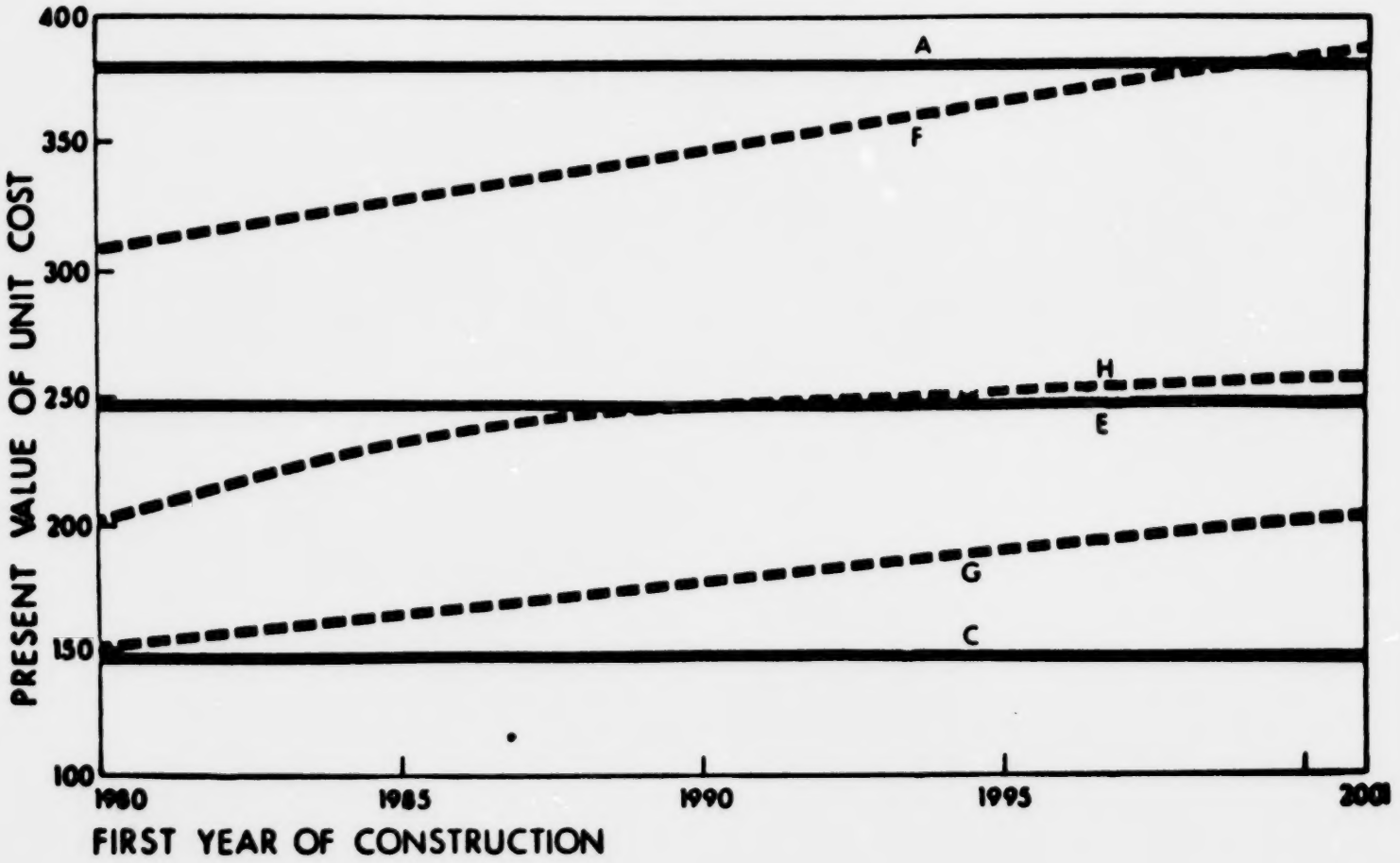


FIGURE 3.2: RESULTS OF ECONOMIC ANALYSIS - METHANOL

- gas conversion costs are very sensitive to feedstock costs
- coal conversion costs are very sensitive to capital costs

There are many characteristics of methanol which must be examined to determine its suitability as an alternative fuel. Some of the advantages and disadvantages are listed below.

Advantages:

(1) It is cleaner burning than conventional fuels.

(2) It is liquid and therefore compatible with existing infrastructure. This characteristic makes methanol more acceptable to consumers.

(3) It is less expensive than higher alcohols.

(4) It has a high octane rating.

An added advantage is that methanol has been successfully tested as an alternative fuel. It is currently being used in fleet operations in California and sold commercially as a gasoline extender and octane booster in Europe.

Disadvantages:

(1) It corrodes plastics, rubbers, and metals found in the cars fuel system and at the service station.

(2) Problems with starting engines in cold weather; any water in the gas tank leads to a phase separation of gasoline and methanol.

(3) Engines require an increase in compression ratio to take advantage of the high octane. After this adjustment, the engine may not run on 100 percent gasoline.

(4) The clear burning flame is dangerous.

With improved technology, most of those problems can be overcome: new developments in rubber materials would alleviate the problem of corrosion; the addition of iso-pentane to the gasoline-methanol mixture would prevent phase separation; and an additive would transform methanol into a visible flame.

Interest in methanol has been increasing because of favourable indications for use as an alternative fuel (either as a gasoline extender or as 100 percent methanol) and as a petrochemical feedstock.

However, there are presently many problems inherent to the development of any alternative fuel that must be surmounted. These include:

- the need for the development of infra-structure for the production, distribution and storage of the fuels
- the presence of technical uncertainties
- competition due to subsidized feedstock for gasoline in the short-run and to the vast oil sands potential in the long-run

Concluding Remarks

Currently Alberta is Canada's largest center of production of conventional energy. This position will likely continue, considering potential oil production from the oil sands. Alternatives must, however, be investigated to assure the optimal pattern of resource development. Methanol may have an advantage over other options being considered in the long-run, since it is relatively inexpensive to produce with existing technology from feedstock which has large proven reserves.

Discussion

Q. There are substantial amounts of natural gas being flared in the Middle East. Will this affect the development of methanol as an alternative transport fuel?

A. At present, there are no facilities in place for transporting natural gas from its source to the point of consumption. However, once a transportation system is established, Middle Eastern natural gas may compete with methanol in the transportation sector.

Q. What is presently the cost of methanol derived from coal?

A. It is reported to be approximately $0.90 per gallon (U.S.). This closely approximates the value of $1.11 per gallon (Canadian) mentioned in this presentation.

Q. According to your figures, a vehicle will travel only 65 percent of the distance on a gallon of methanol as on a gallon of gasoline. This seems low compared to some figures I have seen. How do you account for this?

A. The value 1.65 is based on a Btu conversion factor of 0.52; that is, methanol has only 52 percent of the heat energy content of a gallon of gasoline. It is not unusual to see different values quoted for this conversion factor. These differences are frequently reflected by the conditions under which the tests were performed.

4. Gasohol Production

A.E. Meyer, P. Eng.
R.D.C. Research, Development & Consulting Ltd.

Introduction

It is my pleasure to come to you today to speak about a new industry on the verge of its introduction to Manitoba and Canada--gasohol.

I represent R.D.C Research, Development & Consulting Ltd., a firm established to investigate opportunities in alternate energy fields with the certain knowledge that our present bountiful supply of oil has a limited life and that action must be commenced in the near future in order to avoid a liquid fuels crisis in years to come.

R.D.C is a small firm that draws on inputs from scientific sources of all kinds as required, assembles data into economic format and decides on action of a near-term or long-term nature.

I am speaking to you as a research consultant who has been instrumental in presenting the case for gasohol to the Mohawk Oil Co. Ltd. and will discuss today the background and operation of the Minnedosa ethanol plant being developed by Mohawk Oil Co. Ltd.

Why Gasohol?

Canada does not have a total energy shortage. We have vast reserves of natural gas, coal, timber, tar sands, nuclear fuels, water power and even peat.

Our shortage lies in the popular liquid fuels derived from crude oil. We are presently short of crude oil by about 400,000 barrels per day and forecasts indicate that our domestic production is going to decline a further 600,000 barrels per day by 1986. Thus we will be looking for 1,000,000 barrels per day by 1986 to keep our habit supplied. Frankly I do not think we will be able to find that much oil on the world supply system considering that the U.S.A., Japan, Europe and

many emerging countries are also going to be bigger buyers of world crude.

Remember, the remaining life of the world's crude oil is only 15 or 20 years at the present rate of consumption. By 1986 the world production rate is going down slightly from the 1980 rate, so how are we going to find more oil to buy when there is less available and there are more people looking for it?

Even if we can find enough I do not think we can pay for it. At prices like $40 per barrel it would cost Canada $15.6 billion per year in 1986. To offset, our grain exports might make $3 billion. Some deficit!

The conclusion from all this is that we must reduce our consumption of oil products in real terms through every conceivable conservation scheme and hope no serious interruption occurs to our crude oil imports in the next two years. If interruption--rationing.

Also we must start developing alternative fuels on both a near-term and long-term basis. With concerted effort we will have a hard time converting more that 100,000 barrels per day to alternative energy forms by 1986 including engines converted to propane, compressed natural gas and alcohol fuels.

To make 10,000 barrels per day of ethanol requires a 130 million gallon plant that would produce one-third of Manitoba's gasoline consumption. This is a tall order but is possible.

If we are lucky we may have some new large projects such as tar sands, heavy oil upgrading and Newfoundland offshore oil production generating an additional 100,000 barrels per day by 1986 and we may be able to arrest the decline of Canadian production and hold it to about 800,000 barrels per day.

Before this time Canada will find it necessary to ration our liquid fuel and stimulate development of alternative fuels on a crash program.

We think planning should be done on a more orderly basis.

A Partial Solution

The only new source of liquid fuel or replacement for liquid fuel, other than propane and natural gas, that can be introduced quickly is alcohol. An alcohol plant can be built in two years, a small plant can be built in one year. Small owner-operated plants can compete in some circumstances with large plants. Plants can be built everywhere in Canada that biomass grows so that does not miss many locations.

Alcohol plants only cost about $2 per annual gallon of capacity compared to $4 or $5 per annual gallon of tar sands plant.

Some distilleries are still operating after 150 years on the same site. The plant and the feedstock are permanent and dependable.

The Minnedosa plant being developed by Mohawk will require about 22,000 tonnes of feed barley at its initial throughput and will be expanded up to about 30,000 to 40,000 tonnes per year within a year.

This will yield about 8 million litres per year rising to 15 million a year later. This is less than 1 percent of Manitoba's gasoline requirements.

Discussion of Minnedosa Operation

If the scenario that I described earlier unfolds on schedule we will see 150 million gallon per year plant capacity installed during the next three years at an investment cost of $300 million. This much plant capacity would require about 2 million tonnes of grain per year commencing with the crop harvested in the fall of 1983. This would put some strain on Manitoba farmers, but I think it is much more possible than it will be to find 1,000,000 barrels per day of crude oil from foreign suppliers. I do not really know the numbers but I think 2 million tonnes of grain would only be about a 15 percent increase in total Manitoba grain production. I think that could be done without sacrificing export market and farm revenues would be increased by $1/3 billion.

Much has been said about the efficiency of producing alcohol from grain. When there is not enough liquid fuel to go around, those arguments will disappear. Operating

efficiencies can be introduced in modern power alcohol plants that will permit them to yield twice as much alcohol energy as the total input from farming and plant fuel.

Much has been said also about the ethics of converting food to fuel. We must remember that it is feed grain that is being converted, not grain commonly consumed directly by humans. If we want to be moralistic we should stop feeding corn and barley to cows and supply that grain directly to people rather than go through the terribly inefficient conversion of grain to beef. There is a potential benefit to Canada and to the hungry world in the extraction of starch for alcohol in Canada and the transport of about 30 percent of the grain as a high protein concentrate which is vastly required by underdeveloped countries who have lots of starch but not sufficient protein. The concentrate would require one-third the number of rail cars, would cost one-third the freight to move equivalent amounts of protein nutrients, and would permit us to increase production of grain without clogging our rail and terminal system.

It has been calculated that the protein content of the corn fed to U.S. cows is sufficient to supply the required protein ration of all the people in the world. Please let us stop moralizing about conversion of food.

There is also some concern about the price of alcohol compared to gasoline. It is a fact that today alcohol can be manufactured competitively with gasoline made from crude oil at world prices. Canadian crude oil is presently subsidized by over $20 per barrel which effects a wholesale price of gasoline about 22 cents per litre below world prices. If that subsidy were applied to alcohol it would be fully competitive and would probably remain equal or better than gasoline in future as oil supplies become more precious and alcohol technology improves.

The future of alcohol production beyond the immediately urgent need to get started with known technology is a very interesting study. I think there is more challenge to agronomists in the next ten years than has ever been experienced in the history of Canadian agriculture. For the first time there is going to be pressure on the agriculture industry to produce as much as the system can reasonably put out while protecting and enhancing the soil to preserve its longevity.

Many of the ground rules will change because we will not grade crops for alcohol on milling quality or protein content but on alcohol yield per acre in combination with a marketable by-product of fibre/protein/minerals in a form that can be assimilated by animals or humans.

We discovered a great lack of information available on alcohol yield and by-product value from corn, barley, utility wheat, rye and triticale. Of course there has been no need for such data. But how are we going to buy grain for the Minnedosa plant unless we have analyses of the various grains?

We have recently completed some laboratory analyses that reveal some interesting trends. We will do more work in the months to come to refine and verify the results. Barley, for instance, shows an increase in starch percent (dry basis) as the grade goes lower. As you would expect, the fiber increases for lower grades (explaining the lower bushel weight) and protein content decreases. The same trends apply to corn and utility wheat. When we tried to find compiled analyses of different grades of various grains we could not find published data on anything except protein content.

If the alcohol industry puts enough pressure on grain production to cause problems of supply, price or distribution, the attention will turn to other crops. Sugar beets show some potential if the price of sugar comes back down to earth. There are some problems related to storing of beets long enough to sustain continuous plant operation all year.

We propose to sponsor some experiments on Jerusalem Artichoke. It is indicated that yields of 20 tonnes per acre of tubers might be harvested from soil that might be doubtful for grain. This would yield 500 gallons of alcohol per acre as compared to a normal expectation from barley land of 130 gallons per acre or from corn land under irrigation of 240 gallons per acre.

The tops of Jerusalem Artichoke may also be harvested prior to the plant flowering. Sugar in the form of inulin is stored in the stem until flowering at which time it is transferred to the tubers. If tops are harvested in two cuttings they may well yield more alcohol than the tubers. Tops may be winnowed, baled and stored like hay with only about 5 percent drop in sugar content.

There is much to be learned about growing, harvesting and processing Jerusalem Artichoke, but at those kind of yields it is worthy of pursuit. Apparently the plants do not deplete the soil excessively and only need rotation every four or five years and are immune to all diseases and pests except one or two in certain varieties.

Beyond the challenge of growing grains and tubers is the possibility of converting cellulose to alcohol. There is no commercial process available at present, but there is work proceeding all over North America on process development to cheaply isolate the cellulose from the lignin that binds it in wood and plant stems. Canada has a couple of processes that are well out in front and will probably go into pilot plant stage with the help of Canertech Inc., the alternate energy counterpart to Petro Canada, to be set up in offices in Winnipeg. If we learn to convert straw to alcohol, the yields from farm acreage may be increased by up to 50 percent and we can begin to look at a different equation for alcohol.

Aspen farms are another possible source of feedstock for alcohol. There is potential to re-forest and maintain a continuous permanent supply of liquid fuel if the process can be made effective. Probably long before tree farms can be developed there will be alcohol plants in production using waste wood scraps and sawdust from sawmills.

As long as the distillation process is used to separate alcohol from mash there will be a stream of waste hot water available from a power alcohol plant. This stream will contain a certain amount of nutrients and lends itself to use in a hydroponic greenhouse adjacent to the plant. It happens that Mohawk has 100,000 square feet of warehouse space that is heated and insulated with a 21 foot ceiling standing vacant next to the plant. If any of you should have any leads to proven hydroponic technology we would be interested in examining the possibility.

In our energy equation we are very closely tied to the U.S.A. in terms of economic cause and effect. We can be illustrated like the people in a big open stake poker game, that has been going on for a long time. As the night wears on and dawn is approaching, gradually the players fold because they have run out of chips or because they have become too tired. Finally the game boils down to one North American

and one Russian. The North American has been drinking and eating and laughing and having a great old time. But he kind of shakes himself and looks through fuzzy eyes across the table and sees the Russian with two big piles of chips: yellow ones which are gold reserves and black ones that are oil reserves. The Russian has only had one beer and a ham sandwich. The North American had a big pile of yellow chips, but by being frivolous this pile has become smaller. He formerly had a huge pile of black chips, but he sold some and loaned some and was using them up fast. He forces himself to think even though his head does not work too well from lack of use. He begins to consider his options. He decides he only has three.

His first option would be to pull a gun and take all the chips away from the Russian. However, the Russian is big and tough and in good shape and the odds are not good.

His second option is to stop drinking and play very, very carefully to preserve his chips as long as possible.

His third option is to put some new chips in the game and go after it with vigor and clear up his head. The only chips he has available are green chips, which are biomass, but he can keep on coming up with those.

This is a big game we are playing. The modest beginning at Minnedosa does not mean that much by itself, but perhaps we might all shake our heads and look at what is happening to our country. The agronomists of Manitoba may be required to ante up in order to keep the game going.

Personally I recommend the third option.

Discussion

Q. You have suggested that ethanol at $0.55 per litre could compete with conventional gasoline. How do you account for this?

A. To begin with, this value is based on a very low throughput. Secondly, I believe that there will be a considerable decline in the cost of feedstocks available in the future. Decreasing feedstock costs from $150 per tonne to $80 per tonne coupled with an increased throughput should lower the price of ethanol to $0.43 per litre.

An even lower price could be realized by converting wood chips to alcohol. It has been estimated that the selling price of ethanol would be $0.12-$0.15 per litre FOB at the plant gate.

Q. Is ethanol subject to a provincial road tax?

A. Presently gasohol is exempt from a road tax in Manitoba. Gasoline is taxed at $0.057 per litre. I am not sure when the tax will be instituted on ethanol. It will depend to a large extent upon the rate of consumption over the next few years.

Q. What portion of $0.55 per litre selling price is accounted for by the cost of fuel for running the ethanol facility?

A. Indirectly, the cost at the Minnedosa plant is approximately $600,000 per year. In terms of energy consumed for energy gained, the plant requires 80 Btu's for every 100 Btu's produced. This is a rather high ratio; however with increased efficiency, we hope the ratio will decline to about 50 Btu's consumed for every 100 Btu's produced.

The fuel used to produce ethanol is natural gas.

Q. Will a vehicle operate on 100 percent ethanol?

A. A car will run on 100 percent alcohol; however, engine modifications are required. For a vehicle to efficiently operate without any modifications, up to 20 percent ethanol may be added to gasoline.

5. Propane as an Alternative Fuel

General Discussion

Supply

Mohawk and Cigas currently market propane, while Husky will shortly be moving into this area. Approximately one-half of the propane produced in Canada is exported, with the United States being the major consumer. Depending upon the rate at which vehicle conversions occur and the extent to which propane is used in enhanced oil recovery, the supply of propane for use in Canada may not be secure. If supply constraints develop, exports to the U.S. could be scaled down. It has been estimated that approximately 450,000 vehicles in Canada could be fuelled by the amount of propane currently exported. The use of propane as an alternative fuel could displace 20,000 barrels of crude oil per day, which is 5 percent of the oil consumption in Canada.

Vehicle Conversions

The 1980 National Energy Program provided for taxable grants of up to $400 for each vehicle of a commercial fleet converted to propane. It is believed that there are presently 200-300 propane-powered vehicles operating in the Calgary area. Ontario has set a 1985 target of 40,000 for the number of vehicles converted to propane. It is believed that in Ontario, the major determinant of the conversion rate is not economics, but a combination of marketing, institutional factors and government policies and taxes.

Price

There is some controversy as to whether the price of propane tracks the price of crude oil or the price of natural gas. This relationship has important implications for the future rate of vehicle conversions. Historically, the price has tracked the price of bunker crude. If the historical relationship still applies, given the faster rising price of oil compared to natural gas, the price spread between propane

and gasoline may stay constant or may even decrease. Propane conversions under these circumstances look unfavourable. Dr. B. Yang from the Ontario Ministry of Energy believes that the price of propane is tracking the price of natural gas. On that basis, propane becomes more attractive as an alternative fuel.

6. Coal Pyrolysis - The Production of Oil from Coal

Z. Kolisnyk
Vice President, Development
Fording Coal Limited

Excerpts from the paper "Coal Pyrolysis - The Third Alternative", given at the 33rd Canadian Conference on Coal, Regina, Saskatchewan, September 20-22, 1981.

The economic pressures which have made the recovery of 'non-conventional' oil from tar sands and oil shale a viable proposition today, are rapidly advancing the time when oil from coal will not only be strategically attractive, but also economically viable.

Technology exists for converting coal to oil and there are some notable project successes. The primary objective of all processes is to enhance the atomic hydrogen/carbon (H/C) ratio of coal, typically in a range of 0.5-1.0, to a range of 1.5-2.0 consistent with residual and crude oils.

Liquefication processes are conventionally categorized as using either direct or indirect routes to increase the H/C ratio of coal feedstock. Direct routes involve the reaction of coal with a hydrogen-rich solvent under conditions which favour the transfer of hydrogen atoms to the coal structure, whereas indirect routes typically utilize the production of synthesis gas (carbon monoxide and hydrogen), involving addition of hydrogen via steam injection and removal of carbon via carbon dioxide scrubbing, followed by catalytic conversion to liquid hydrocarbons. This latter approach is employed on a commercial scale at SASOL, South Africa.

It is perhaps ironic that the process which is probably more economically attractive than its counterparts fits into neither of these two categories. This is coal pyrolysis --the 'third alternative.'

While other processes are designed to maximize the conversion of coal to liquid hydrocarbons, pyrolysis opts for less than total conversion by a technique involving the removal of carbon. In pyrolysis, coal is heated in an inert atmosphere to produce a gaseous stream and a solid char residue. Rapid quenching of the pyrolysis gas results in partial conversion to a liquid hydrocarbon product. Flash pyrolysis processes incorporating both rapid heating of the coal and rapid quenching of the pyrolysis gas have been shown to maximize liquid yields and are therefore preferred for this application.

One of the major attractions of the pyrolysis process is that hydrogen demands of downstream processing are minimized and can be generated internally by stream reforming of product gas. Another advantage is that the characteristics and quantities of the major products can be adjusted to suit market demands by varying the operating conditions of the pyrolysis reactor. However, since over 50 percent of the gross heat in the coal feedstock may be 'rejected' from the process in the form of char and excess product gas, the development strategy for a pyrolysis facility must include careful consideration to marketing of not only liquid product streams, but also char and surplus product gas. A natural application of the process is in its marriage with a coal-fired power plant since the utilization of the resources, as represented by an overall energy balance, will be enhanced. In such a facility, the liquid hydrocarbons would be skimmed off the coal and the char residue plus surplus product gas may be used to feed the power plant. The product gas may alternatively be used as a petrochemical feedstock.

A current project for which this concept has been examined is the Alberta Electric Power Project (AEPP), a proposal for a 2000 MW power plant located in central Alberta having Alberta Power Limited, Fording Coal Limited and TransAlta Utilities Corporation as sponsors. The project would employ coal from Fording's Heatburg property which contains a typical western plains sub-bituminous coal having a HHV of 15 775 kJ/kg and ash and moisture contents of 27 percent and 18 percent by weight respectively.

The integration of this process with the proposed power plant presents a number of benefits. The base loaded

power plant would be an eligible consumer of char and excess gaseous products from the process, utilization of the coal resource would be enhanced, and the time scale of the project, proposed to commence operation in 1991, appears consistent with the developmental status of the process. Studies to determine technical and economic feasibility were commenced in mid-1980 and are ongoing.

Other projects involving this concept are being promoted by Utah Light and Power, U.S.A., and State Electricity Commission of Queensland, Australia.

While there are many proprietary pyrolysis processes, each in varying states of development and having differing product objectives, only a small number have the particular attributes or are in a sufficiently advanced state of development to be mentioned in the context of this paper.

The Lurgi-Ruhrgas (LR) process is undoubtedly the most proven of available technologies. Initial development prompted by the desire to produce town gas from coal, resulted in a pilot plant being built in Dorsten, Germany in the late 1950's. This was followed by the construction of two 1600 t/day units in Yugoslavia in 1963 to produce char for use as an additive to coke. Two smaller units, 350 t/day and 700 t/day, were later built in Germany and Great Britain respectively for the purposes of producing char fires from bituminous coals for hot briquetting.

Renewed interest in the LR process for the purpose of producing liquid products from coal, resulted in the recent construction of 24 t/day pilot plant in Frankfurt, Germany. This unit will be used to develop process improvements and test various feedstocks.

The Occidental Research Corporation (ORC) process has been in development for over 12 years, and while a 3 t/day demonstration unit was operated between 1976 and 1978, this has now been dismantled. The ORC has made a number of developmental improvements to increase liquid yields, circumvent reactor fouling problems, and to produce higher qualify liquid products. A 2.25 kg/h bench scale test unit is currently being used to predict probable performance of test coals and assist in a program to better understand the chemistry of the process.

As with the Lurgi process, the main product streams are char, excess product gas and liquid hydrocarbons.

Our initial review of the LR and ORC processes indicated that while the ORC process had not been demonstrated on a full scale installation, the potential for enhanced oil yield and oil quality, coupled with superior char combustion characteristics resulting from finer feedstock grind, appeared to make this the more attractive prospect. The ORC process was therefore selected as the basis for preliminary technical and economic feasibility studies on the Alberta Electric Power Project.

Consideration was also given to the Toscoal Ceramic Ball Process utilizing the inert heat carrier concept. However, the oil yields obtained from this process cannot match those obtained by flash pyrolysis. Other process developments using fluidized bed technology are in progress and worthy of future consideration.

The need for rigorous field sampling and testing of coals prior to their commitment to power generation, process, or metallurgical services is now generally acknowledged within the industry. In many cases, the design of process equipment fuelled by coal remains an art rather than a precise science and thorough characterization of a project coal from chemical and physical analyses, bench scale, pilot and even full scale trials are considered an essential pre-investment step to limit project exposure.

This is particularly important for state-of-the-art processes such as pyrolysis, where coal characteristics not only impact upon the design and cost of process components, but also upon the relative quantities, qualities and characteristics of the various products, all of which can individually have a significant influence on project viability. There is no better example in this case than that of oil yield.

Fischer Assay or Grey King tests are routinely used to predict probable oil yields from pyrolysis processes and most proponents of the technology have developed correlations between standard Fischer Assay tar yields and those expected from their processes. A more direct and reliable route to predict pyrolysis yields and product quality is by use of

bench scale pyrolysis test rigs. Both Lurgi and Occidental have such facilities but their limited availability and cost of operation prohibits extended use during initial feasibility stages of a project.

For flash pyrolysis, oil yields varying from 130 percent to over 200 percent of Fischer Assay yields have been quoted. Our limited experience on the AEPP has demonstrated that these correlations should be used with considerable discretion due to variability in performance for different coal types and the limited amount of hard test data available. It would appear, however, that standard tests such as Fischer Assay can be used as a convenient low cost reference once a meaningful number of bench scale pyrolysis tests have been conducted on a particular coal deposit to confirm reliable correlations.

The characteristics of coal ash are as important in evaluating coals for pyrolysis as they are in boiler applications since the coal ash concentrates in the char which will therefore exhibit similar fouling potential in both the pyrolysis reactor system and subsequent char-fired boiler surfaces. Ash fusion temperatures and mineralogy are critical in this regard.

Useful work has been commenced in Australia to develop correlations between pyrolysis oil yield and atomic H/C ratio of the coal. Investigations into depressed oil yield attributed to cat ion components in coal ash have also been conducted. This work could prove relevant to our current studies on western sub-bituminous coals although further work is required to prove applicability.

As previously indicated, the pyrolysis process can be operated under a variety of conditions designed to favour production of either gaseous or liquid products, or to achieve particular char characteristics. In this application, it is generally recognized that the most economic proposal is likely to result in conditions designed to maximize liquid products. A considerable amount of work has been undertaken to establish optimum operating conditions to achieve this objective and most proponents agree that a pyrolysing temperature of 600°C meets these requirements.

Both Lurgi and Occidental have achieved oil yields of 25 percent M.A.F. weight basis from relatively low ash (less

than 6 percent) sub-bituminous coals, this being equivalent to 188 percent and 200 percent of the Fischer Assay yield for the LR and ORC processes respectively. Oil yields of 30 percent have been reported by Occidental for bituminous coals and similar yields at specific H/C ratios have been achieved by CSIRO, Australia, in their fluid bed pyrolyser.

Work on the AEPP indicated that these values cannot be achieved from our high ash sub-bituminous coal at Heatburg where pyrolysis oil yields of less than 10 percent M.A.F. weight basis and 15 percent M.A.F. weight basis were obtained in bench scale pyrolysis tests conducted by Lurgi and Occidental respectively. However, while the prospect of fairly low oil yields was initially discouraging, further examination of the products revealed some potentially off-setting benefits.

It became clear, for example, that the liquid products produced at these lower yields tended to be of a lighter fraction than those obtained from coals with higher tar content and should therefore be more amenable and less costly to upgrade. Furthermore, since a decrease in oil yield is partially offset by a corresponding increase in gas yield, our attention was directed toward the possible use of this gas as a petrochemical feedstock for selective removal of higher hydrocarbons as either a substitute for or pretreatment to combustion of excess product gas in the power boilers. Our evaluation of these opportunities is ongoing.

The total marketable products for a complex of this type would include oil, char, product gas, sulphur, ammonia and phenols. The char, supplemented by some coal and part or all of the product gas, would be used in the power boilers. Table 6.1 shows a typical product slate and their expected characteristics for a pyrolysis complex matched to a 2 000 MW power plant using a typical western Canadian sub-bituminous coal feedstock. In this case, a 20 percent M.A.F. weight basis oil yield and ORC technology is assumed.

A few comments are appropriate on the char and product gas characteristics. It will be seen that the heating value of the char slightly exceeds that of the parent coal despite a doubling of the ash content. This largely results from a corresponding reduction in moisture and oxygen content during the drying and devolatilization stages. It should be

TABLE 6.1

TYPICAL FLASH PYROLYSIS PRODUCT SLATE AND CHARACTERISTICS
2000 MW POWER PLANT USING WESTERN SUB-BITUMINOUS COAL

PRODUCT		
1. OIL		
28.1° API	17 580 BPSD	
14 ° API	2 712 BPSD	
4.1° API	4 794 BPSD	
TOTAL	25 086 BPSD	
2. CHAR	18,100 TONNES/ DAY	
C 38.27	70% 200 MESH	
H 2.91		
N 0.65		
S 0.19		
O 1.60		
ASH 56.38		
100.00%		
HHV	16 820 kJ/kg (7250 BTU/LB)	
3. SULPHUR	81.5 TONNES/DAY	
4. AMMONIA	77.5 TONNES/DAY	
5. PHENOL	26.0 TONNES/DAY	
6. PRODUCT GAS	1.7 m Sm^3/DAY	
MOLE % ANALYSIS		
H_2	13.90	
CO	32.62	
CH_4	26.20	
C_2H_4	10.97	
C_2H_6	4.28	
C_4H_{10}	3.47	
C_5H_{12}	0.53	
C_6H_6	1.34	
CO_2	0.27	
	100.00	
HHV	37.86 mJ/Sm^3	(1015 BTU/DAY)
MW	28.5	

NOTES: Sub-bituminous coal quality - HHV 15 775 kJ/kg (6800BTU/lb); Ash 27%; H_2O 18%; S 0.3%
Oil yield - 20% M.A.F. Weight Basis
4 x 500 MW Power Plant at 75% Load Factor
Occidental Research Corporation Technology

BPSD - Barrels Per Stream Day

noted that in view of the flexibility of the process, the char can be selected through optimization to have a heating value higher, lower or equal to the original coal.

A further and important characteristic of the char is its sulphur content, approximately 63 percent of that in the parent coal, which would make this a compliance fuel under the recently issued National Guidelines for New Stationary Sources, Thermal Power Generation Emissions. For comparison purposes, a power plant fuelled directly with the example coal would require approximately 30 percent SO_2 removal from the flue gases in the event that the National Guidelines are adopted as regulations. This is typical for many prospective power plant installations in Alberta.

The utilization of chars in power boilers is receiving the attention of major equipment manufacturers and institutions. Since the physical and chemical nature of chars vary considerably for different processes, it is difficult to generalize. Some chars are amenable to direct firing in conventional pulverized fuel-firing systems whereas others would require further pulverization or use of fluid bed technology. Also, some chars are more reactive than others which require supplementary fuel addition to sustain ignition. This only serves to stress the importance of determining the characteristics of these products since the impacts on system and equipment design and operability can be substantial. Char arising from the ORC pyrolysis system appears to be suitable for direct firing in conventional dry bottom pulverized fuel fired boilers.

Our economic studies were initiated with prior knowledge of attractive evaluations conducted by others. Our prime objective on the AEPP was to firstly assess a number of scenarios and sensitivities based on realistic technical, cost and financial assumptions, to be followed by more detailed analysis of a selected case.

The initial studies were based on technical input from ORC, cost estimates prepared by an independent engineering consultant and our own financial parameters. A model of the facility was used for financial analysis. Because of time constraints, initial economic studies were conducted in parallel with coal sampling and associated tests to characterize the coal and products of pyrolysis. The second stage

of analysis, which is nearing completion, will utilize specific data obtained from our testing program.

Preliminary cost estimates indicate that a decoupled three-train pyrolysis facility capable of processing 38 500 t/day of run-of-mine coal should cost about $1.3 billion in 1981 Canadian Dollars. A 20 percent M.A.F. weight basis oil yield was assumed. For this scenario, and based on required revenues using a cost of service approach, the required oil selling price would be approximately $55 per barrel when the entire facility is in operation and with a levelized price of $35 per barrel over the expected life of the facility, all prices being in 1981 Canadian dollars.

It is self-evident that a prerequisite for any such project will be a guarantee of world price for oil products.

The extent to which the impact of lower oil yields may be offset by potentially higher values assigned to excess gaseous products and also by the production of a compliance fuel in the context of National Emission Guidelines are matters which should be answered by ongoing studies. While we have identified that a close coupled scheme will result in significant cost savings and a consequential reduction in the required oil selling price from $55 per barrel to $47 per barrel, this goal would not be achieved with initial projects employing the process. A greater degree of integration is however probable once the technology has been adequately demonstrated.

It should be evident that if initial feasibility studies provide sufficient encouragement to warrant further examination of this concept, then a substantial development program will be required.

We envisage that such a program would include a period of further bench scale testing followed by the commitment of a demonstration unit in the 850 t/day ROM coal capacity range. Such a unit would preferably be located at an existing power plant which could be used to test burn the char produced. The Wabamun Thermal Plant of TransAlta Utilities Corporation or the Battle River Plant of Alberta Power Limited having 60 MW and 30 MW units respectively, would probably be suitable.

An 850 t/day demonstration unit would have a single reactor of approximately one tenth the capacity of that

required for the full-scale installation thereby providing for realistic scale-up. This unit would be used to prove system design and performance on western sub-bituminous coals and further our knowledge of product characteristics.

Such an installation would probably be industry rather than project oriented and could warrant combined industry and government funding.

Projects using advanced technology have a long lead time. The development program shows that immediate commencement of a program would be required in order to incorporate the concept in a power plant scheduled for service in the early 1990's. One of the main contributory factors is the need for sufficient performance data from a demonstration unit to permit key pre-investment decisions to be made during initial design phases of the power plant, five to six years in advance of the in-service data.

Concluding Remarks

The use of coal for power generation purposes will increase substantially in western Canada towards the end of this century. In Alberta, the Electric Utility Planning Council has forecast an increase of 10 000 MW in required power generation capacity between 1989 and 2005, of which about 6 500 MW is expected to be coal-fired.

Coal pyrolysis, when used in conjunction with power generation, provides an opportunity to enhance the utilization of our western coal reserves during this period of rapid expansion. While the oil output from one plant would be modest, a number of facilities installed over a period of years could together make a significant contribution to our incessant demand for liquid fuels.

While base technology exists, its further development and application to our western coals will require much effort and perseverence. The long lead times involved necessitate forward planning and initiation of suitable development programs now if this technology is to be applied to projects coming on stream in the 1990's. The initial requirement is for a concerted effort by industry to categorize our western coals and the products of pyrolysis, and to further examine process viability based on project specific data. On the

Alberta Electric Power Project, we have commenced this process of evaluation.

Staged development programs and assurance of obtaining world price for oil products are essential prerequisities to demonstrating viability and obtaining required financing for such projects.

Discussion

Q. What is the predicted required selling price per barrel for crude oil produced in a coal pyrolysis facility, such as the one you have described?

A. It must be reiterated that for this project and any such projects to be viable, the world price for oil products must be guaranteed. The required oil selling price for the initial year of operation would be $55/bbl. However, as the facility comes into full operation, the required selling price will decline and a levelized price of $35/bbl is projected over the expected life of the facility. This is of course in 1981 Canadian dollars. This is a stand-alone price and does not account for the effect of operating a coal pyrolysis facility in conjunction with a coal-fired power plant.

Q. What is the quality of crude from the point of view of the refiner?

A. The crude produced from a typical western subbituminous coal feedstock would be very amenable for use as a diesel fuel. Some further refining and upgrading would be necessary.

Q. Are there presently facilities available for refining the crude?

A. There are options to be considered. Refineries at the site of crude production have not been included in the proposal. However, the crude could be transported to Edmonton for upgrading or specialty refineries could be constructed to accomodate the output from the pyrolysis plants.

Q. What regulations presently govern coal plant emissions in the context of the acid rain controversy?

A. The current acid rain standard does not make flue gas scrubbing mandatory. However, if the recently issued National Guidelines for New Stationary Sources, Thermal Power Generation Emissions, are adopted as regulations, even low sulphur coals will require scrubbing. The example coal would require 30 percent SO_2 removal for it to be a compliance fuel under the new guidelines. The char from the same example contains 0.2 percent sulphur.

Q. What would be the cost of char to a power plant?

A. The char would be priced at the same level as the coal equivalent.

Q. What would be the tonnage requirement of a 2000 MW generating plant?

A. A facility of that size would utilize 42,000 tons of coal per day or 15.3 million tons per year. This quota could easily be supplied by the local coal reserve.

Q. How much oil would be produced by facilities consuming that amount of coal per day?

A. Approximately 80,000 to 100,000 barrels per day would be produced.

Q. What would be the cost of a demonstration plant which would utilize 850 t/day and how would it be funded?

A. A demonstration unit capable of processing 850 t/day would cost in the neighbourhood of $25 million. As is the case with new technologies, extremely high costs are involved and, invariably, government support is required.

7. Compressed Natural Gas as an Alternative Fuel

Richard E. Wyman
Director of Research, Canadian Hunter Exploration Ltd.
and
Vice President, CNG Fuel Systems Ltd.

The 1980's will become known as the decade of mass conversion to alternative fuels. Methane-powered vehicles will almost certainly lead this conversion effort in many countries around the world. The arguments for converting to methane (especially compressed natural gas known as CNG) are simply too compelling:

- supply is plentiful in short and long-term
- practical technology exists today
- costs are lower because of plentiful supplies, inexpensive processing, and easy transportation
- infrastructure is in place with natural gas pipelines
- fuel is non-toxic and safe
- engine conversion is simple
- environmental damage is significantly reduced
- methane burns more efficiently with higher octane (130) than gasoline
- engine life is extended
- engine operation is smoother
- vehicle maintenance is reduced
- easier starting in cold or hot weather
- fuel may be easily switched from natural gas to gasoline or back again while driving in dual fuelled vehicles
- fuel pilferage is eliminated

Before we can seriously discuss any alternative fuel that might have widespread application, we need to understand if the potential supply is adequate. In the case of natural gas the worldwide supply appears overwhelmingly promising. This is the main reason (along with its lower cost) that methane is considered more attractive as an alternative fuel for mass conversions than other candidates, such as propane or butane (LPG). As with crude oil, certain parts of the world are blessed with more natural gas than others; but, the technology of moving natural gas from one part of the world to another is also rapidly improving.

Figure 7.1 shows a resource triangle for natural gas in North America. It shows that while a large amount of gas is available in so called conventional reservoirs, an enormous amount is available in lower quality formations such as tight sands, coal seams and geo-pressurized water. The cost of extracting the gas and the requirement for improved technology increases as you move down through the triangle. These two factors will become increasingly more acceptable with our growing need for greater energy supplies.

At the bottom of the resource triangle is synthetic natural gas from renewable resources such as recovery from waste or biomass conversion. Studies at the Institute of Gas Technology, on methane recovery from kelp and other rapid growth water plants are pointing the way to potential large scale conversion systems. By farming marine biomass from deep water off the shores of North America, it is estimated that several times the current natural gas production in North America could be generated.

Of course, the key to all these unconventional sources of natural gas are economics and technology, but many of these methods are expected to be economically competitive with conventional gas during the coming decade. The main point is that there is no need to be concerned about a shortage of methane as long as the free market can determine the source.

Canada is in an enviable position with respect to natural gas reserves. The projected 300 year demand for natural gas in Canada is 600 trillion cubic feet. At the moment there is an established supply of 90 trillion cubic

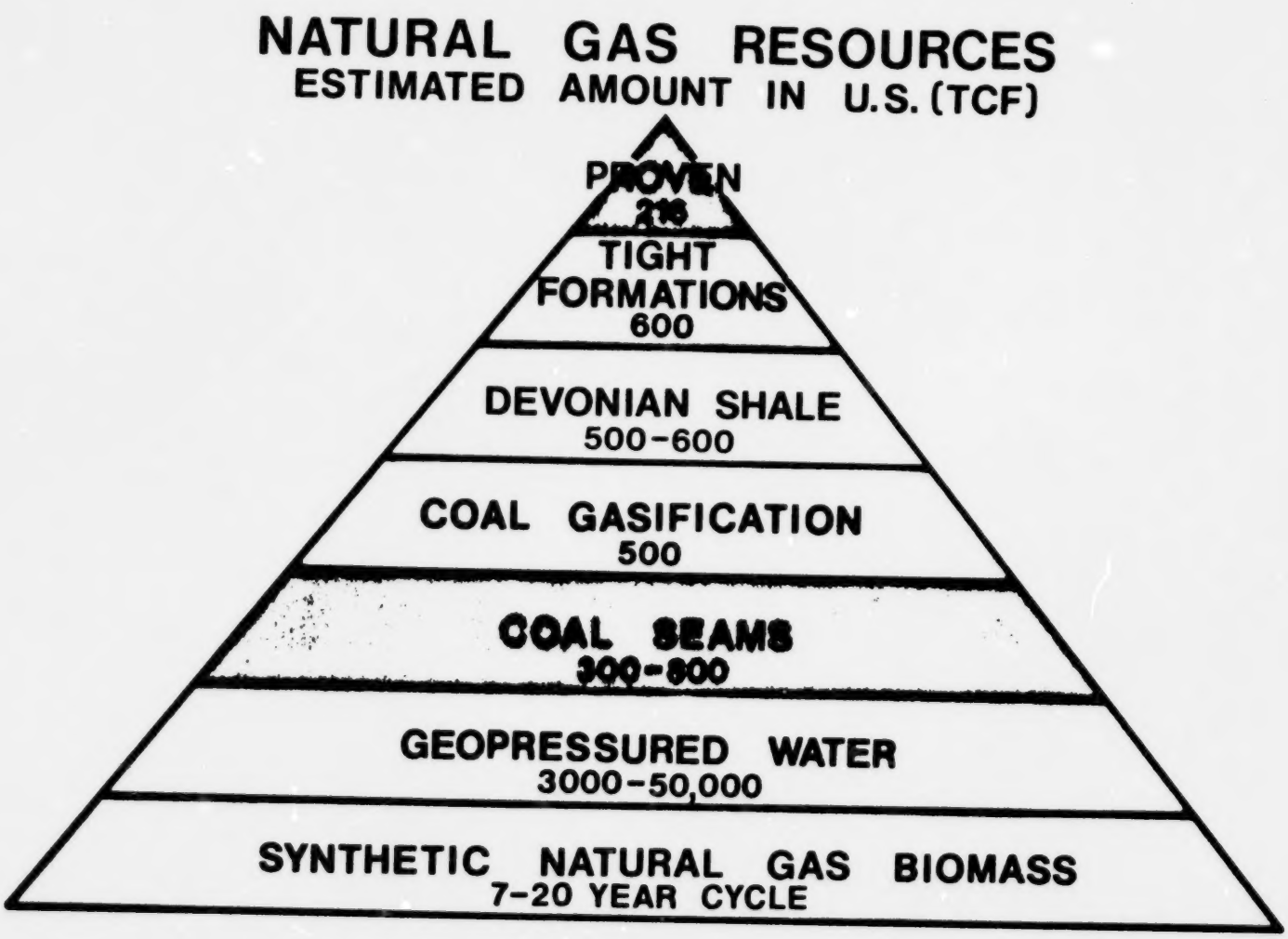


FIGURE 7.1: NATURAL GAS RESOURCES

feet and indications of an additional 1200 trillion cubic feet presen^ in areas such as the Beaufort, Arctic, and offshore East Coast.

Transport of Natural Gas

It used to be thought that widespread use of natural gas was limited to those areas near the source. The technology of transporting natural gas has grown rapidly over the past decade and will certainly continue to expand during the next decade. Very long pipelines overland or underwater are now commonplace. Huge LNG (liquified natural gas) tankers regularly deliver natural gas from surplus gas areas of the world such as the Middle East and Southeast Asia.

A couple of recent examples of how new pipelines will drastically change the energy use in countries around the world, is the offshore Thailand development and the TransMediterranean lines. The Thailand line is the longest submarine pipeline in the world with 264 miles underwater. This line will be capable of delivering 500 million cubic feet per day from the Gulf of Thailand to the doorstep of Bangkok. Bangkok's streets are now choked with smog-creating vehicles burning imported liquids. Here is just one example where methane-powered vehicles could significantly improve the environment and economy at the same time.

Another record breaking line which spans the Mediterranean from Tunisia through Sicily across the Strait of Messina, to a point near Bologna, will deliver over 1.2 billion cubic feet per day from the giant Hassi R'Mel field in Algeria to Italian markets.

This gas will supplement that from the Po Valley and other imports for the use in methane powered vehicles in Italy. It should give a significant boost to the security of supply for over 250,000 methane-powered vehicles now operating in the central and northern part of Italy.

Meanwhile, intercontinental movement of natural gas has increased many times over the past decade by LNG tankers. These tankers are presently moving large amounts of natural gas each year. Further increase of this traffic is expected when satisfactory long-term pricing negotiations are

completed. A typical LNG tanker with 125,000 cubic meters of LNG could fuel 10,000 to 20,000 vehicles for a year.

In brief, world wide transportation systems are now in place and improving each year to economically distribute surplus gas. Because of this, many more places in the world will now be able to convert to a stable natural gas economy as crude oil supplies become scarce, expensive and insecure.

Notable Activities in Natural Gas Around the World

Italy

To Italy goes the honour of being the leading country in the world in the use of CNG. They have been using CNG since the early 1920's; now there are about 260,000 vehicles operating on CNG. These are mostly private vehicles, refuelling from about 250 stations in northern and central Italy around the Po Valley.

Some of these stations are quite large and can accommodate as many as 40 vehicles at a time, although the average station has about 6 refuelling ports.

A variety of vehicle conversion systems, storage cylinders, and compressors are manufactured in Italy specifically for CNG operation. This early start in the development of technology for CNG has led to a rapidly increasing worldwide export market for Italy.

Italy has an enviable safety record with CNG. During the past 30 years, there have been no accidents or explosions attributable to CNG components. Although CNG vehicles were involved in their fair share of accidents during hundreds of millions of miles of travel, no injuries or deaths were caused by CNG.

New Zealand

In mid-1979, the government of New Zealand announced an ambitious plan to convert 150,000 vehicles to run on natural gas by the end of 1985. The incentives for New Zealand to convert to natural gas are quite evident when one realizes that they must import virtually all their crude oil while a great surplus of natural gas is within easy access to the north island. The giant offshore Maui gas field and the

Kapuni field together contain about 6 trillion cubic feet of proven reserves.

In January, 1981, New Zealand had 24 refuelling stations with an additional 15 under construction. To date, about 4,000 vehicles have been converted with more being added every week. Training courses have certified over 1,000 mechanics. These trained mechanics along with new government incentives should accelerate the rate of conversions in the future.

The government of New Zealand has decreed that all appropriate Government-run vehicles are to be equipped for CNG. In addition the government is offering cost grants (eg., 25 percent on cost of refuelling equipment and $200 per motorist for conversion) and accelerated tax writeoffs.

Activities in Canada

The importance of CNG to the future of Canada was given official Federal recognition in the National Energy Program of 1980. The government stated that it was interested in the potential to use CNG as a motor fuel in Canada and anxious to encourage the development of this new option.

Since that time, it has been moving aggressively with private industry and provincial governments to insure the speedy and safe implementation of this alternative fuel. The prime motivation for this is that Canada is presently importing more than 600,000 barrels per day of crude oil while surplus natural gas is shut-in. The annual cost of this in 1980 was over 8 billion dollars. This figure is expected to be far greater by 1985.

Canada has been averaging an addition of almost 5 trillion cubic feet per year to its proven reserves for the past five years. In 1980 only 1.5 trillion cubic feet was used in Canada while slightly under 1 trillion cubic feet was exported. If markets and reasonable prices prevail in the future, there is every reason to believe the industry can continue to add at least this amount each year. In fact, a more realistic figure by 1990 would be an annual addition of 8 trillion cubic feet with contributions from the frontier areas. By 1990 the National Energy Board (NEB) estimates less than 3 trillion cubic feet will be needed within Canada even with expanded domestic markets (eg., as to the Maritime provinces) to be served by the proposed pipelines. If

500,000 high mileage vehicles were converted to run on CNG, they would require only about 0.1 trillion cubic feet per year.

Nearly 200,000 barrels per day of crude oil are required to provide gasoline for this number of vehicles. This is equivalent to two-thirds of Canada's net imports. Such a projection would still leave Canada with an annual surplus of over 5 trillion cubic feet per year which could be available for export in 1990; this, of course, is dependent upon deliverability. Further substitutions of natural gas for fuel oil, gasoline and diesel fuel could bring Canada significantly closer to energy self-sufficiency within a decade.

The National Energy Program outlined certain incentives including support of demonstration fleets and the necessary fuel facilities through the existing Federal-Provincial Energy Demonstration Agreements, and, as necessary, directly by the Government of Canada. After standards for Canadian CNG Systems are approved it is anticipated that incentives will be provided for CNG along the lines of those proposed for propane conversions. The 1980 program provides for taxable grants of up to $500 for each vehicle of a commercial fleet converted to propane.

In addition to these incentives, individual provinces are actively seeking ways to encourage the use of alternative fuels. Ontario, for instance has removed the retail sales tax on vehicles powered exclusively by alternative fuels which include natural gas. Also, Ontario has eliminated the gasoline sales tax on alternative fuels. The province of British Columbia is actively promoting interest in methane-powered vehicles and providing research grants and helping to educate the public. Alberta has also expressed a great deal of interest and is expected to announce their program to encourage use of CNG shortly.

A committee has now been established under the sponsorship of the Canadian Gas Association to recommend safety codes for CNG conversions and refuelling stations. Representatives from various levels of government and industry are working together to ensure that safe and reasonable codes will guide the conversion efforts.

Canada has been experimenting with methane-powered vehicles for over ten years. However, some of the earlier experiments lost momentum primarily because of the unsatisfactory cost/benefit ratios with artificially low prices of gasoline. Other reasons cited included lack of refuelling stations, loss of power in older vehicles, maintenance problems with the older compressors and high taxes on natural gas (these taxes have now been removed in Ontario).

Most, if not all, of these drawbacks are rapidly dissolving as the price of gasoline continues to increase. It is predicted that the price of gasoline will reach $3.50-$4.00/gallon by 1986. In general, the price of CNG is 55 percent of the price of gasoline. This ratio makes CNG an attractive alternative. In addition, the newer technologies in compressors and vehicle conversion are helping to overcome previous problems of maintenance and loss of power. The 'chicken and egg' cycle of number of methane-powered vehicles and refuelling stations now appears to be started with the commitment of commercial interests and the concurrent emerging provincial and federal encouragement.

The sensitivity of the payback to the price of gasoline is illustrated in Figure 7.2. This graph (based on Alberta prices) shows the increasing savings that result from using CNG as the price of gasoline goes up even though the price of natural gas and operating costs of the refuelling station are assumed to increase proportionately. In this example a taxicab that uses 30 000 litres (7,925 U.S. gallons) per year could save $5,600 each year if the price of gasoline is $0.25 per litre ($0.95 per U.S. gallon). As the price of gasoline doubles, the savings increase to $11,358 per year even though the price of natural gas has also increased. This example assumes that the price of natural gas is $2.00 per 1,000 cubic feet when the price of gasoline is $0.25 per litre.

In summary, Canada has strong national incentives for converting to methane-powered vehicles. Furthermore, the federal and provincial governments are co-operating with private industry to implement an aggressive program of using alternative fuels during the coming decade.

Estimated annual savings from CNG conversion is strongly dependent upon price of gasoline (Courtesy of CNG Fuel Systems Ltd.)

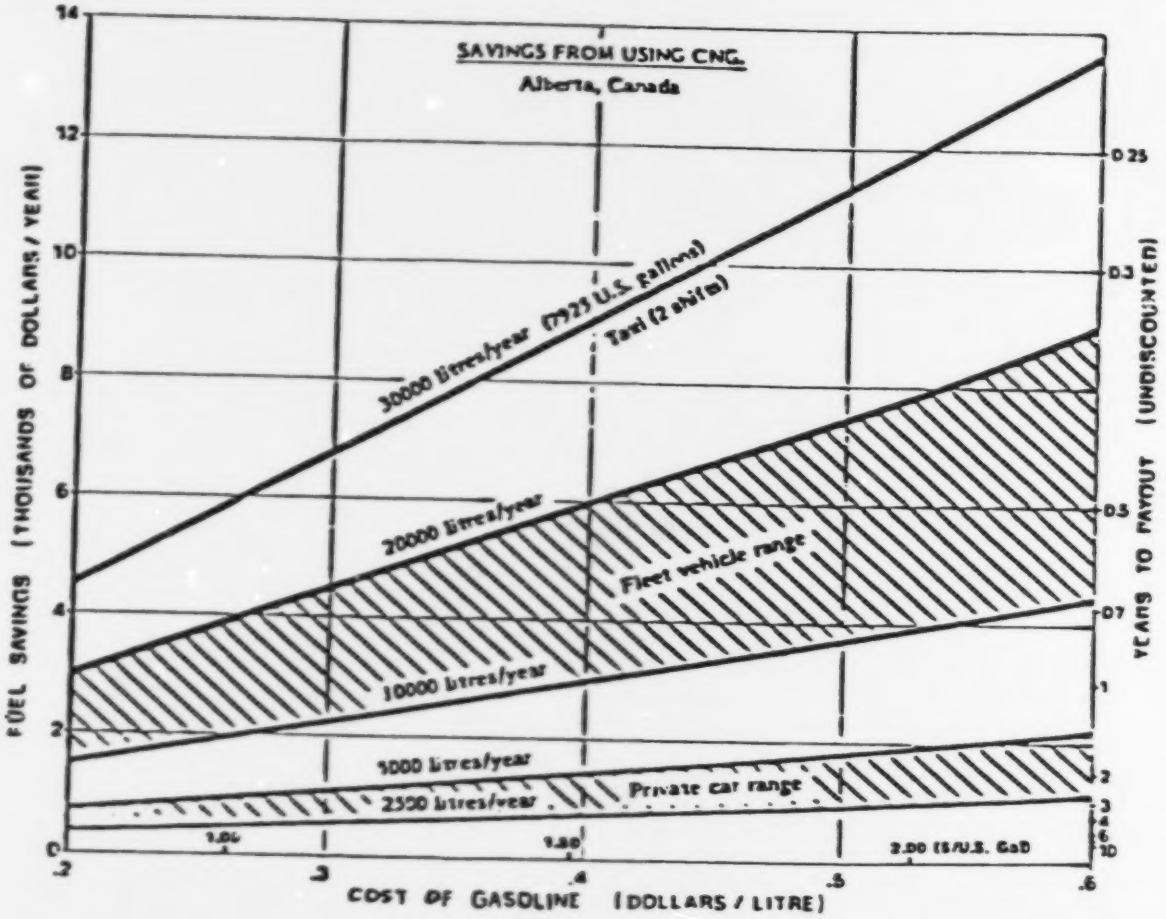


FIGURE 7.2: SAVINGS FROM CNG USAGE

Research and Development

The basic technology for methane-powered vehicles is well established and practical conversions are being made daily around the world. However, as with any relatively new technology, there is considerable room for further research and development. The primary areas of investigation for CNG include:

- refuelling stations
- fuel storage
- spark ignition engines
- diesel engines
- chemistry and physics of gaseous fuels and combustion.

Conclusions

There is very strong interest around the world in methane-powered vehicles. Compressed natural gas technology has been proven economical, safe and environmentally clean by about 300,000 vehicles currently in use. Although Italy, United States, and New Zealand are leading the world in conversion to compressed natural gas for vehicles at this time, there is strong interest in many other countries. Canada, in particular, appears on the threshold of moving ahead aggressively to start replacing gasoline with their surplus natural gas.

It is becoming abundantly clear that while there are huge proven reserves in the world, there are far greater potential methane resources yet to be developed. Besides the conventional natural gas reservoirs, there are sources from tight sands, coal seams, fractured shales, ultra deep basins, geopressured waters and hydrates. An increasing amount of research is also being done on renewable methane resources.

Research by private industry, government, and universities is expected to accelerate during the early 1980's for CNG. Experimentation with LNG is also continuing in several countries; however, the application to vehicles has been limited to date.

It is expected that CNG usage will increase very rapidly during the 1980's. There will be a great challenge to meet the expected demand for new equipment and trained

personnel to engineer, install and service conversions to methane-powered vehicles.

Discussion

Q. Is there currently any federal support to manufacturers of CNG equipment, distributors of CNG or to individuals wishing to convert his vehicle to CNG?

A. The federal government presently has no firm policy for CNG. However, in the recent National Energy Program, considerable interest in pursuing investigations into the economics and practicality of CNG conversion was expressed. It is anticipated that federal money will be available to certain fleet vehicles to demonstrate CNG as an alternative fuel. Funding is expected to be similar to that available for propane.

Q. What is the cost of converting a typical vehicle to a CNG system?

A. At the moment the cost of conversion is around $2300. Once manufacturers produce the equipment domestically, the cost should decline.

Q. What portion of the retail price of CNG is due to the cost of compression?

A. It costs the equivalent of 1-2¢ per litre to compress natural gas (operation and maintenance costs).

Q. Will major auto manufacturers install CNG systems in some vehicles as standard equipment in the future?

A. That possibility does exist and could reduce the cost of conversion considerably.

Q. What do you perceive as the major constraints to mass conversion from gasoline to CNG?

A. The lack of refuelling stations is one constraint. A manufacturing plant located in Brampton, Ontario will produce about 200 compressors per year, however, it will take some time before these compressors are installed in centers throughout Canada.

A second constraint is the lack of materials and trained individuals to effectively implement a widespread conversion program.

Some critics view vehicle range as a limitation to CNG. This should not be seen as a problem, especially if CNG is used in combination with a gasoline system. Typically, a CNG car would carry two 60-litre tanks pressurized to 3000 psi. On average, a vehicle with tanks of these dimensions could travel over 150 miles. On long distance trips where CNG refuelling stations may be sparsely located, vehicle range can be extended by switching to normal gasoline service until a refuelling station can be reached.

Q. What will be the market price of CNG in Calgary?

A. CNG will be marketed on an equivalent mileage basis. The price should be approximately 50 to 60 percent of the price of gasoline. The price of raw natural gas at the 'gas station' is expected to be the same as the price for utilities.

Q. Could you approximate the amount of CNG required to travel a distance equal to that travelled on a gallon of gasoline?

A. 120 cubic feet would be approximately equivalent to a gallon of gasoline.

8. Hydrogen as an Alternative Transport Fuel in Ontario

B. Yang
Manager, Transportation and Community Energy Management
Ontario Ministry of Energy

Ontario, like other Canadian provinces, is faced with the challenge of ensuring its future energy security. Due to the lack of indigenous hydrocarbon reserves, Ontario has undertaken an energy program consisting of three fundamental components: conservation and imposed efficiency of energy use; substitution for conventional oil-derived fuels with alternative fuel sources; and development of new energy supplies (such as energy from biomass). To encourage substitution for oil in transportation, the province has instituted a system of incentives by removing road fuel taxes for all alternative fuels and is anticipating that, because of these incentives, 40,000 to 100,000 vehicles will be operating on propane by 1990.

The need to identify and develop indigenous energy forms in Ontario, which could compete with other energy sources, is compelling. Presently about 26 per cent of the energy consumed in the province comes from indigenous sources such as uranium and hydraulic power. However, in an effort to achieve provincial energy security, the target is to reach 37 percent by 1995. The opportunity to achieve this goal is present in the form of electricity. Electricity can be used directly or as the feedstock to produce another convenient and portable fuel--hydrogen.

Hydrogen is most commonly produced today by extraction from a hydrocarbon source such as natural gas. A currently more expensive method of production is electrolysis, which involves using electricity to separate water into its component parts--hydrogen and oxygen. Table 8.1 shows that, within ten years, electrolysis could become an economic alternative to the production of hydrogen from natural gas and by the year 2000, electrolysis could be the preferred method of hydrogen production. These estimates are contingent upon the construction of hydrogen-committed nuclear facilities

TABLE 8.1

HYDROGEN (H_2) COST FORECASTS
$(1980)/GJ

	1980		1990		2000	
	Low	High	Low	High	Low	High
H_2 - NFD[a]	8.2		7.5	8.1	5.6	6.6
H_2 - SMR[b]	5.2		7.9	9.8	10.7	11.8
Electricity (H_2)	4.9		5.2		3.9	
SUPPLY PRICES						
H_2, R	10.6		10.1	10.7	8.4	9.4
H_2, C	9.0		8.3	8.9	6.4	7.4
H_2, T	12.1 - 13.5		11.5	13.6	9.9	12.5
CNG	5.6 - 7.0		7.6	10.0	8.9	11.4
Propane	6.2		9.4	11.0	11.6	13.1
Methanol	9.8 - 10.4		11.9	13.5	13.5	15.2
Gasoline	5.6		9.1	10.6	11.5	13.5

[a]Electrolytic hydrogen (non-fossil derived)

[b]Hydrogen derived via steam methane reforming

which, because of high load factor and production capacity, could supply electricity at a cost lower than the average cost of electricity from the bulk power system currently in place.

There is the potential to produce vast quantities of hydrogen by electricity within the next 15 to 20 years. The earliest large-scale application of this hydrogen would most likely be to replace the more costly hydrogen produced from natural gas being used at that time in oil refineries. Hydrogen from electrolysis could also be used in the production of methanol from wood and would result in a reduction in the capital cost and the amount of biomass feedstock required for the process.

However, for hydrogen to have the greatest impact on provincial energy security, it would have to penetrate the transportation sector as a fuel rather than just as a feedstock. There exists the potential for hydrogen to power high mileage vehicles, such as buses and trucks, and for liquid hydrogen to be used as a fuel for air transport. The cost of electrolytic hydrogen as a transportation fuel has been projected to increase more slowly than forecast Ontario prices for carbon-based fuels (these projections assume no real cost increases for electric power generation facilities). Hydrogen in the long-term does appear to be an attractive alternative; however, lack of data on fuel supply costs of other fuels, power system costs and total systems efficiency makes it impossible to compare hydrogen to carbon-based fuels on a systems basis.

In order to accelerate the prospects of hydrogen as an alternative fuel, the Ontario government has proposed that a hydrogen research institute be formed in conjunction with the federal government.

Discussion

Q. Why do electricity costs peak in 1990 and then decline after that until the year 2000?

A. Electricity prices are projected to decline after 1990 provided that planned nuclear facilities come on-stream by then. Prices will peak in 1990, because of the increased

cost of fossil fuels. Also, at that time planned additional nuclear plants will not have begun operation.

Q. How much lead time is required to build hydrogen committed nuclear facilities?

A. A decision to build hydrogen committed nuclear facilities requires 12 to 15 years lead time. For a facility to be ready by 1995, decisions must be made shortly.

9. Impact of Public Regulations and Taxing Differentials on Alternative Transport Fuels

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Today, I propose to limit my contribution to this symposium to remarks on the development of Canada's energy policies and the impact this has had on the current and future economic climate facing promoters of alternative transportation fuels.

Introduction

One of the major problems facing the Canadian economy today and over the next decade is that the demand for crude oil in the form of refined petroleum cannot be met by domestic supply alone. This problem will be exacerbated in the latter years of the decade as conventional domestic oil production continues to decline. Currently Canada makes net purchases of approximately 150 million barrels per year from world oil suppliers. The dichotomy arises from the fact that Canada is a net exporter of energy, in the form of natural gas, propane, butane, methanol and electricity. It would therefore appear logical to consider utilizing surpluses in exported energies to displace domestic requirements for crude oil imported at the prevailing international price. The importance of the transportation sector to the total requirement for crude oil is reflected in the volume consumed during 1980, some 350 million barrels, in excess of 50 percent of the total crude oil requirement. A key problem to be addressed in Canada during the 1980's is the supply and availability of liquid transport fuels.

(The issues that face the producers and marketers of alternative transport fuels are as much economic as political.) Governments and the agencies and departments under their jurisdiction have instituted and continue to advocate policies of increased involvement in the private sector. The position that the business community finds itself in, is one

of coping with a myriad of government regulations, taxes and incentives initiated in the past and being prepared for further government initiatives in the future.

The recent federal/provincial constitutional accord once again confirmed the division of powers between the federal and provincial governments. This division of power between levels of government in Canada and the consequent question of jurisdiction provides the backdrop to government policies and regulation in the energy sector and the implications for the development of alternative transport fuels in Canada.

Canadian Energy Policy - Background

Federal government marketing and price regulation in the Canadian energy sector is not a current phenomenon but rather stems back to the establishment of the Ottawa Valley Line by the National Oil Policy Legislation of 1961. The result of this legislation was higher priced Alberta crude oil meeting the crude requirements of Ontario and the western provinces with lower cost imported oil supplying the requirements of Quebec and the Maritimes.

With the advent of OPEC and the subsequent price increases in international crude oil, the National Energy Board (NEB) during 1973, recommended to the federal government that the price of domestic crude oil be controlled at its current level, approximately $3.80 per barrel. The upward pressure on international crude oil prices exerted by the OPEC nations continued, and by the end of the Arab-Israeli confrontation in 1974 international crude prices had tripled from the beginning of the year.

At this point the Canadian government introduced a policy of gradual increases in the price of domestic crude oil, designed to allow the Canadian economy time to adjust to the higher international price. To achieve this objective, the federal government instituted the import compensation program. Under this program, refiners purchasing crude oil were compensated for the differential between the regulated low domestic price and the imported crude oil price. This resulted in the average refinery cost of crude oil in Canada equalling the domestic price of crude oil.

During the years 1974 to 1980 international crude oil prices continued to increase. Negotiations between the Alberta and federal governments resulted in increases to the domestic crude oil price of up to $2 per barrel per year, significantly below the increase in the international price over the same period. By 1980 the gap between the domestic and imported crude oil prices reached about $20 per barrel in current Canadian dollars, and in constant 1973 dollars the differential was $9 per barrel. This is in sharp contrast to 1973 when imported and domestic crude oil prices were at par.

The increasing gap between the real import and domestic crude oil prices demonstrates that Canada was not keeping pace with increases in the world oil price. Therefore, the economic incentive of higher oil prices necessary for the conservation of energy and introduction of energy alternatives did not exist.

This is contrasted by the ability of many industrialized nations who, unlike Canada, did not have the luxury of low cost domestic oil production and were unable to buffer the effects of higher international oil prices. These countries, Germany, Japan, France and Britain have made the adjustment to higher energy prices through conservation and energy systems designed to take advantage of alternative fuels.

Canada's reluctance to allow the domestic price of crude oil to increase at the same rate or close to the same rate as international crude oil prices, has impeded the introduction of energy alternatives to crude oil in all sectors of the economy.

The National Energy Program

The National Energy Program (NEP) tabled in the House of Commons on October 28, 1980 has as a component of the overall strategy the 'off-oil programs.' With statements similar to the following:

> The National Energy Program establishes the basis for a truly dramatic shift in Canada's pattern of energy use away from oil toward gas, electricity, renewable energy and coal. This off-oil conversion program, therefore is a cornerstone of the drive towards independence from the world oil market within the decade.

There appeared to be a priority commitment by the federal government to provide the necessary framework to achieve the goal of independence from the world oil market. With reference to alternative transportation fuels under the off-oil program, the NEP framework mentioned two alternatives to gasoline: propane and compressed natural gas (CNG). The only concrete incentive for alternative transport fuels came in the form of a taxable grant of up to $400 to be provided for each vehicle converted to propane. The other potential alternative transport fuel referred to in the document, CNG, was deemed not sufficiently developed to warrant an incentive. The commitment by the federal government in the case of CNG, was to encourage programs that would provide information to determine the best way to support CNG conversion.

The major policy decision within the National Energy Program was the use of a price mechanism to encourage the penetration of alternate fuels in all sectors of the economy. The pricing framework designed to achieve this goal included:

(1) The domestic price of crude oil, the blended price, was scheduled to increase gradually to 85 percent of the international crude oil price, and

(2) The domestic price of natural gas as a proportion of the blended crude oil price was designed to fall, to approximately 65 percent.

With the above price relationships established, the thrust of the NEP was to create an attractive economic climate for natural gas in the marketplace, relative to the blended price of crude oil.

The price mechanisms established in the National Energy Program clearly provided natural gas with a preferential position in the marketplace relative to other alternative fuels. In the case of propane as an alternative transportation fuel, economic viability in specific applications (e.g., fleet vehicles) had previously been proven in some areas of Canada. It is particularly noteworthy to mention that in Ontario the exemption of the gasoline tax on propane was the primary factor in establishing its ability to compete. The introduction by the federal government of a $400 taxable grant as an incentive to

convert to propane carburetion clearly enhanced propane's position in the marketplace.

With respect to other alternative transportation fuels under consideration today, ethanol, liquified coal and hydrogen, the National Energy Program provides little if any encouragement for their development. In fact the NEP policies and programs will effectively constrain the development of alternatives to gasoline other than natural gas, propane and perhaps methanol.

Events subsequent to the introduction of the National Energy Program suggest that the federal government did not take into consideration the historical relationship between competing energy forms. This was particularly evident in the case of propane, where the product price is not regulated and historically has competed in the heating market. With the advent of blended crude oil price increases, as per the NEP, the price of propane moved in concert. It appeared that the federal government had anticipated that natural gas liquids, particularly propane, would enjoy a similar relative price advantage to crude oil as natural gas. This situation led to an attempt at moral suasion by the Minister of Energy in the form of a letter to propane producers and wholesalers suggesting that the price of propane should track the price of natural gas, and if it continued to track crude oil price increases, export allocations would be carefully examined.

To add to the confusion surrounding the federal government commitment to alternative transport fuels, a natural gas and gas liquids tax (NGGLT) was imposed on all export and domestic sales of natural gas, ethane, propane and butane. To the extent that the tax can be passed on to the consumers in the form of higher prices and in the case of a product with a regulated price, the imposition of such a tax is an impediment to the penetration of natural gas or natural gas-derived product conversion schemes in the transportation sector.

The federal government did make a commitment to alternative transport fuels in the NEP; however, this commitment was directed to natural gas and natural gas-derived fuels. The failure of the National Energy Program to treat all alternative transport fuels in an equitable manner could

result in a severe misallocation of energy resources in the near future.

The Ottawa/Alberta Price Agreement

On September 1, 1981, less than one year after the introduction of the National Energy Program, the federal and Alberta governments negotiated a new pricing agreement for domestic crude oil and natural gas. Under this agreement there is no commitment by the federal government to prevent the blended oil price from reaching parity with imported international oil prices. Natural gas prices will, however, continue to be pegged at 65 percent of the average refinery crude cost at the Toronto City Gate.

Although the current pricing agreement commits Canadians to higher domestic crude oil price increases than those under the NEP, there is still a large discrepancy between the domestic blended price and imported crude oil prices. Estimates for 1981 reveal that the differential between imported crude and the domestic blended crude price will be approximately $15 per barrel. This differential is expected to approach zero by the mid-eighties. Albeit, national energy pricing policies have been designed to increase domestic oil prices to a level comparable to imported crude prices, it appears this time it will occur by default. The current circumstances surrounding international crude oil prices, i.e., excess supply in world markets resulting from conservation and economic recession, suggest that price increases in Canada's domestic supply of crude will significantly exceed increases in the international price until at least the mid-1980's.

Earlier, the implications of the natural gas and gas liquids tax to alternative transport fuels were stated. It is noteworthy to point out that the tax was significantly modified in the Ottawa/Alberta pricing agreement. The NGGLT under the NEP was set at 30¢/MMBtu in late 1980 increasing to 90¢/MMBtu in 1983, including the 15¢/MMBtu Canadian Ownership Levy. The modified version of the NNGLT is anticipated to increase from 50¢/MMBtu in 1981 to approximately $2/MMBtu in 1990.

The implications of this tax are of considerable significance to a government program designed to attain

energy self-sufficiency by 1990. As it was pointed out earlier in the text, the NGGLT, to the extent it can be passed on to the consumer in the form of higher prices, creates an impediment to the marketing of the product. In the case of a product with a regulated price, if the supply of energy product in the marketplace is the same regardless of the tax, it appears that penetration gains could be made by the removal of the tax from natural gas and natural gas-derived fuels. The removal of the tax would increase the competitiveness of these fuels without hindering the supply available in the marketplace.

The stated objective of the federal government in the NEP to encourage displacement of oil in the transportation sector (the largest consumer of petroleum products in Canada) is inconsistent with the programs designed to make this a reality. The programs and pricing mechanisms place natural gas and natural gas-derived fuels in a preferential position relative to gasoline and all other potential fuels. The recent Alberta/Ottawa pricing agreement appears to provide the economic incentive required to develop and bring to the marketplace by the mid-eighties alternative transportation fuels competitive with the price of imported crude oil. The problem that exists with respect to alternatives to gasoline, other than natural gas-based fuels, is that the ability to compete with imported crude will no longer be the full measure of an energy products ability to compete in the domestic market. By the mid-eighties the measure of an alternative energy product's ability to compete could be the price of natural gas or natural gas derived products.

The initiatives brought forth by the federal and provincial governments with respect to alternative transportation fuels, clearly have little regard for the future potential of domestic oil resources. The alternative transport fuels being addressed today may only be transition fuels in view of the future potential of domestic oil sources such as the Alberta tarsands, the Beaufort and Hibernia to displace imported crude. Future competition and indeed future government initiatives will determine the role to be played by alternative transportation fuels in Canada's energy future.

The future direction of Canada's national energy policies are open to speculation. My predictive powers have

been severely shattered by three successive failures: (1) the October 28, 1980 budget; (2) the outcome of the recent Alberta/Ottawa pricing agreement; and (3) the November 12, 1981 budget. With reluctance I submit that governments in Canada will continue to have a major influence on the decisions of both producers and consumers in the energy sector through regulation of the price mechanism, the tax system, incentives and moral suasion with little regard for fundamental underlying economic forces.

Appendix

List of Participants at CERI Seminar:
Economic Potential for Alternative Transportation Fuels
November 17, 1981

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Ian Burn	Alberta Energy and Natural Resources
Larry Caine	Home Oil Company
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John Dawson	Consultant
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Fred Friesen	Ocelot Industries
Judith Gibson	CREB, EMR
Gordon Gislason	CERI
Barbara Green	CERI
Terry Hampson	CNG Fuel Systems Ltd.
Doug Haughey	CERI
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Paul Precht	Alberta Energy and Natural Resources
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Heather Webster	National Energy Board
John Weyland	Trans Canada Pipeline
Sam Wong	Alberta Research Council
Richard E. Wyman	CNG Fuel Systems Ltd.
Bunli Yang	Ontario Ministry of Energy

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